Notice of 2005 Annual Meeting • Proxy Statement

American Electric Power
1 Riverside Plaza
Columbus, OH 43215

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

March 15, 2005

Dear Shareholder:

This year's annual meeting of shareholders will be held at The Renaissance Hotel, 6808 South 107th East Avenue, Tulsa, Oklahoma, on Tuesday, April 26, 2005, at 9:30 a.m. Central 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, March 2, 2005, are entitled to vote and attend the meeting. PLEASE NOTE THAT YOU WILL NEED TO PRESENT AN ADMISSION TICKET TO ATTEND THE MEETING. 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.

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.eproxyvote.com/aep**
- **By toll-free telephone at 877-779-8683**
- **By completing and mailing your proxy card in the enclosed envelope**

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,

Michael G. Morris

NOTICE OF 2005 ANNUAL MEETING

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

TIME . . . . 9:30 a.m. Central Time on Tuesday, April 26, 2005

PLACE . . . . The Renaissance Hotel
6808 South 107th East Avenue
Tulsa, Oklahoma

ITEMS OF BUSINESS . . . . .
(1) To elect 11 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 2005.
(3) To consider and act on a proposal to approve amendments to the American Electric Power System 2000 Long-Term Incentive Plan.
(4) To consider and act on such other matters, including the shareholder proposal described on page 20 of the accompanying proxy statement, as may properly come before the meeting.

RECORD DATE . . . . Only shareholders of record at the close of business on March 2, 2005, 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 and management's discussion and analysis of results of operations and financial condition. AEP's Summary Annual Report to Shareholders contains our chairman's letter to shareholders, condensed financial statements, and an independent auditors' report.

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 the enclosed proxy card in the postage-paid envelope.
(2) USE THE TOLL-FREE TELEPHONE NUMBER shown on the proxy card.
(3) VISIT THE WEB SITE shown on your proxy card to vote via the internet.

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

March 15, 2005

John B. Keane
Secretary

Our annual meeting of shareholders also will be webcast at http://www.AEP.com/go/webcasts at 9:30 a.m. Central Time on April 26, 2005.

Proxy Statement

March 15, 2005

Proxy and Voting Information

THIS PROXY STATEMENT and the accompanying proxy card are to be mailed to shareholders, commencing on or about March 15, 2005, 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, 2005 in Tulsa, Oklahoma.

Who Can Vote. Only the holders of shares of AEP Common Stock at the close of business on the record date, March 2, 2005, 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 396,413,892 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 enclosed 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 March 2, 2005.

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.

If you are a beneficial shareholder and your broker holds your shares in its name, the broker is permitted to vote your shares on the election of Directors and the ratification of Deloitte & Touche LLP as our independent registered public accounting firm even if the broker does not receive voting instructions from you. Under the New York Stock Exchange (NYSE) rules, your broker may not vote your shares on the proposal relating to the amendments to our Long-Term Incentive Plan, or on the shareholder proposal without instructions from you.

A plurality of the votes cast is required for the election of Directors. Only votes "for" or "withheld" affect the outcome. Abstentions are not counted for purposes of the election of Directors.

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; the amendments to our Long-Term Incentive Plan; and the shareholder proposal. Abstentions and broker non-votes are not counted as votes "for" or "against" these proposals.

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 or Proxy Statement to Shareholders. Securities and Exchange Commission (SEC) rules provide that more than one annual report or proxy statement 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 or proxy statement is being householded indefinitely unless you instruct us otherwise. If more than one annual report or proxy statement is being sent to your address, at your request, mailing of the duplicate copy will be discontinued. If you wish to resume receiving separate annual reports or proxy statements at the same address, you may call our transfer agent, EquiServe Trust Company, N.A., at 800-328-6955 or write to them at P.O. Box 2500, Jersey City, NJ 07303-2500. The change will be effective 30 days after receipt. We will deliver promptly upon oral or written request a separate copy of the annual report or proxy statement to a shareholder at a shared address. To receive a separate copy of the annual report or proxy statement, contact AEP Shareholder Direct at 800-551-1AEP (1237) or write to AEP, attention: Investor Relations, at 1 Riverside Plaza, Columbus, OH 43215.

1. Election of Directors

CURRENTLY, AEP's Board of Directors consists of 12 members. Leonard J. Kujawa, a director of AEP since 1997, will end his service as a member of the Board effective as of the date of the annual meeting; therefore, the Board of Directors has authorized a reduction in the size of the Board to 11 members, effective as of April 26, 2005, as permitted by the Company's Bylaws.

Eleven Directors are to be elected by a plurality of the votes cast at the meeting to hold office until the next annual meeting and until their successors have been elected. AEP's By- Laws 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 AEP's Board of Directors.

The 11 nominees named on pages 3 through 5 were selected by the Board of Directors on the recommendation of the Committee on Directors and Corporate Governance of the Board. The proxies named on the proxy card or their substitutes will vote for the Board's nominees, unless instructed otherwise. Shareholders may withhold authority to vote for any or all of such nominees on the proxy card. All of the Board's nominees were elected by the shareholders at the 2004 annual meeting, except for Mr. Nowell, who was elected a director as of July 27, 2004 by the Board of Directors. Mr. Nowell was recommended to the Board by a director search firm, which was paid a fee to identify and evaluate potential Board members. Mr. Morris and Dr. Hudson, the Presiding Director, interviewed Mr. Nowell and recommended him to the full Board. It is not expected that any of the nominees will be unable to stand for election or be unable to serve if elected. In the event that a vacancy in the slate of nominees should occur before the meeting, the proxies may be voted for another person nominated by the Board of Directors or the number of Directors may be reduced accordingly.

Cumulative Voting. Shareholders have the right to vote cumulatively for the election of Directors. This means that in the voting at the meeting each shareholder, or his proxy, may multiply the number of his or her shares by the number of Directors to be elected and then cast the resulting total number of votes for a single nominee, or distribute such votes on the ballot among any two or more nominees as desired. The proxies designated by the Board of Directors will not cumulate the votes of the shares they represent.

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 appears on page 39.

Nominees For Director

E. R. Brooks

Retired Chairman and Chief Executive Officer, Central and South West Corporation, Granbury, Texas

Age 67

Director since 2000

Chairman and chief executive officer of Central and South West Corporation (CSW) (February 1991-June 2000). A director of Hubbell, Inc.

Donald M. Carlton

Retired President and Chief Executive Officer, Radian International LLC, Austin, Texas

Age 67

Director since 2000

Retired president and chief executive officer of Radian International LLC. A director of National Instruments Corporation and Temple-Inland Inc. and trustee of 26 mutual funds in the Smith Barney/Citi fund complex.

John P. DesBarres

Investor
Park City, Utah

Age 65

Director since 1997

Former Chairman of the Board, President and Chief Executive Officer of Transco Energy Company (natural gas). A director of Texas Eastern Products Pipeline Company, which is the general partner of TEPPCO Partners, L.P., and Penn Virginia GP, LLC, an indirect wholly-owned subsidiary of Penn Virginia Corporation and the general partner of Penn Virginia Resource Partners, L.P.

Robert W. Fri

Visiting Scholar, Resources for the Future, Washington, D.C.

Age 69

Director since 1995

Retired President of Resources for the Future (non-profit research organization). Assumed his present position with Resources for the Future in 2001.

William R. Howell

Chairman Emeritus, J. C. Penney Company, Inc., Dallas, Texas

Age 69

Director since 2000

Retired Chairman of the Board and Chief Executive Officer of J. C. Penney Company. Chairman emeritus of J. C. Penney Company (1997-present). A director of Exxon Mobil Corporation, Halliburton Company, Pfizer Inc., and The Williams Companies, Inc. He is also a director of Deutsche Bank Trust Corporation and Deutsche Bank Trust Company Americas, non-public wholly owned subsidiaries of Deutsche Bank A.G.

Nominees For Director — continued

Lester A. Hudson, Jr.

Professor and the Wayland H. Cato, Jr. Chair in Leadership McColl Graduate School of Business Queens University of Charlotte Charlotte, North Carolina

Age 65

Director since 1987

Professor and the Wayland H. Cato, Jr. Chair in Leadership at McColl Graduate School of Business at Queens University of Charlotte since 2003. Professor of Business Strategy at Clemson University (1998-2003). Retired chairman, chief executive officer and president of Wunda Weve Carpets, Inc. A director of American National Bankshares Inc.

Michael G. Morris

Chairman, President and Chief Executive Officer of AEP and AEP Service Corporation; Chairman and Chief Executive Officer of other major AEP subsidiaries

Age 58

Director since 2004

Elected president and chief executive officer of AEP in January 2004; chairman of the board in February 2004; and chairman, president and chief executive officer of all of its major subsidiaries in January 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. From 1997 to 2003 was chairman of the board, president and chief executive officer of Northeast Utilities, an unaffiliated electric utility system. A director of Cincinnati Bell, Inc. and The Hartford Financial Services Group, Inc.

Lionel L. Nowell III

Senior vice president and treasurer of PepsiCo, Purchase, New York

Age 50

Director since 2004

Senior vice president and treasurer of PepsiCo, Inc. since 2001. Executive vice president and chief financial officer of Pepsi Bottling Group, Inc. from 2000-2001 and senior vice president and controller of PepsiCo, Inc. from 1999-2000. Director of Church & Dwight Co., Inc.

Richard L. Sandor

Chairman and Chief Executive Officer, Chicago Climate Exchange, Inc., Chicago, Illinois

Age 63

Director since 2000

Chairman and chief executive officer of Chicago Climate Exchange, Inc. (a self-regulatory exchange that administers a greenhouse reduction and trading program) since 2003. Chairman and chief executive officer of the Chicago Climate Futures Exchange (a designated contract market regulated by the CFTC) since 2004. Research professor at the J.L. Kellogg School of Management, Northwestern University since 1999. Chairman and chief executive officer of Environmental Financial Products LLC (1993-2003). A director of Millenium Cell, Inc.

Nominees For Director — continued

Donald G. Smith

Chairman of the Board, Chief Executive Officer and Treasurer of Roanoke Electric Steel Corporation, Roanoke, Virginia

Age 69

Director since 1994

Chairman of the Board, Chief Executive Officer and Treasurer of Roanoke Electric Steel Corporation (steel manufacturer) since 1989.

Kathryn D. Sullivan

President and Chief Executive Officer, COSI Columbus, Columbus, Ohio

Age 53

Director since 1997

President and chief executive officer of Columbus' science museum COSI (Center of Science & Industry) since 1996.

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 2004, the Board held eight regular meetings and one special meeting. AEP encourages but does not require members of the Board to attend the annual shareholders' meeting. Last year, all members attended the annual meeting.

The Board has seven standing committees. The table below shows the number of meetings conducted in 2004 and the Directors who currently serve on these committees. The functions of the committees are described in the paragraphs following the table.

DIRECTOR	BOARD COMMITTEES						
	Audit	Directors and Corporate Governance	Policy	Executive	Finance	Human Resources	Nuclear Oversight
Mr. Brooks			X			X	X
Dr. Carlton			X			X	X
Mr. DesBarres		X	X	X		X (Chair)	
Mr. Fri		X	X (Chair)			X	
Mr. Howell		X	X	X	X (Chair)		
Dr. Hudson	X	X (Chair)	X	X			
Mr. Kujawa	X (Chair)	X	X	X			
Mr. Morris			X	X (Chair)			
Mr. Nowell	X		X		X		
Dr. Sandor			X		X		X
Mr. Smith			X		X		X
Dr. Sullivan			X				X (Chair)
2004 Meetings	13	5	2	0	4	7	5

During 2004, no Director attended fewer than 75% of the aggregate of the total number of meetings of the Board of Directors and the total number of meetings held by all committees during the period on which he or she served.

Corporate Governance

AEP maintains a corporate governance page on its website which includes key information about its 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 of Directors, and charters for the Audit, Directors and Corporate Governance and Human Resources Committees of the Board of Directors. The corporate governance page can be found at *www.AEP.com*, by clicking on "Investors" and then "Corporate Governance".

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 and the corporate governance requirements of the Sarbanes-Oxley Act of 2002, including:

- The Board of Directors has adopted corporate governance policies;
- A majority of the Board members are 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 non-management members of the Board of Directors meet regularly without the presence of management, and the independent members of the Board of Directors 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;
- The charters of the Board committees clearly establish their respective roles and responsibilities; and
- AEP has an ethics office with a hotline available to all employees, and AEP's Audit Committee has procedures in place for the anonymous submission of employee complaints on accounting, internal controls or auditing matters.

No member of the Board is independent unless the Board of Directors affirmatively determines that the member has no material relationship with AEP or any of its subsidiaries (either directly or as a partner, shareholder or officer of an entity that has a relationship with AEP or any of its subsidiaries). The Board of Directors has adopted categorical standards it uses to determine whether its members are independent. These standards are consistent with the NYSE corporate governance listing standards and are as follows:

1. A member who is an employee, or whose immediate family member is an executive officer of AEP or any of its subsidiaries is not independent until three years after such employment has ended.
2. A member who receives, or whose immediate family member receives, more than $100,000 per year in direct compensation from AEP or any of its subsidiaries, other than director or committee fees, and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service), is not independent until three years after he or she ceases to receive more than $100,000 per year in such compensation.
3. A member, or whose immediate family member, (a) is a current partner of AEP's external auditor; (b) is a current employee of such firm; (c) is a current employee of such firm who participates in that firm's audit, assurance or tax compliance practice; or (d) was within the last three years a partner or employee of such firm and personally worked on AEP's audit, is not independent.
4. A member who is employed, or whose immediate family member is employed, as an executive officer of another company on whose compensation committee any of AEP's executive officers serve is not independent until three years after such service or employment has ended.

5. A member who is an executive officer or an employee, or whose immediate family member is an executive officer, of a company that makes payments to, or receives payments from, AEP or any of its subsidiaries for property or services in an amount which, in any fiscal year, exceeds the greater of $1 million or 2% of such other company's consolidated gross revenues is not independent until three years after falling below such threshold.
6. A member, or whose family member, serves as an executive officer or director or trustee of a non-profit organization, which receives an amount exceeding the greater of $100,000 or 2% of such organization's latest annual gross revenues, is not independent until three years after such service has ended.

The Board of Directors has affirmatively determined that Messrs. Brooks, Carlton, DesBarres, Fri, Howell, Hudson, Nowell and Ms. Sullivan, all of whom are Board of Director nominees at this meeting, are independent and meet these standards. Mr. Morris is not independent because he is an executive officer of AEP. Mr. Smith, who is Chief Executive Officer of Roanoke Electric Steel Corporation (RESC), is not independent because RESC pays more than 2% of its consolidated gross revenues to an AEP subsidiary for electric service. Although Dr. Sandor currently meets the independence standards, the Board of Directors has determined that he is not independent because of AEP's relationship with the Chicago Climate Exchange (CCX). Dr. Sandor serves as Chief Executive Officer of CCX. AEP is a founding member of the CCX and during 2004 AEP and its subsidiaries transacted trades of greenhouse gas emission allowances on the CCX. AEP paid CCX approximately $51,000 in commissions in 2004. AEP payments to CCX currently do not exceed $1 million but AEP's payments in the future may exceed that threshold. Dr. Sandor is also the Chief Executive Officer of the Chicago Climate Futures Exchange (CCFE), which is an exchange established for trading of SO_2 and NO_x allowances. AEP is the largest trader of SO_2 credits in the U.S. and expects to trade on the CCFE. AEP anticipates paying commissions to CCFE in 2005 in an amount equal to or greater than commissions paid to CCX in 2004.

AEP has designated Dr. Hudson its Presiding Director and he presides over meetings of non-management Directors. Shareholders and other interested parties may communicate with Dr. Hudson and the Board by written inquiries sent to American Electric Power Company, Inc., P.O. Box 163609, Attention: AEP Non-Management Directors, Columbus OH 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 Dr. Hudson.

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 By-Laws.
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.

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

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 41 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*. Shareholders' nominees who comply with these procedures will receive the same consideration that all other nominees receive.

In evaluating candidates for Board membership, the Committee on Directors and Corporate Governance reviews each candidate's biographical information and assesses each candidate's skills and expertise based on a variety of factors. Some of the major factors include whether the candidate:

- maintains the highest personal and professional ethics, integrity and values;
- is committed to representing the long-term interests of the shareholders;
- has an inquisitive and objective perspective, practical wisdom and mature judgment;
- possesses familiarity with AEP's business and industry, independence of thought and financial literacy; and
- possesses a willingness to devote sufficient time to carrying out the duties and responsibilities effectively, including attendance at meetings.

The Board seeks balance by having complementary knowledge, expertise, experience and skill in areas such as business, finance, accounting, marketing, public policy, government, technology and environmental issues and other areas that the Board has decided are desirable and helpful to fulfilling its role. Diversity in gender, race, and background of Directors, consistent with the Board's requirements for knowledge, standards, and experience, is desirable in the mix of the Board.

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

The ***Executive Committee*** is empowered to exercise all the authority of the Board of Directors, subject to certain limitations prescribed in the By-Laws, during the intervals between meetings of the Board. Meetings of the Executive Committee are convened only in extraordinary circumstances.

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 ***Human Resources Committee*** has the responsibilities set forth in its charter, including recommending compensation for the CEO to the independent Board members, approving compensation for other senior officers and making recommendations to the Board regarding incentive and equity-based compensation plans. The Human Resources Committee also communicates the Company's compensation policies to shareholders (as required by the Securities and Exchange Commission).

A copy of the Human Resources Committee charter can be found on our website at *www.AEP.com.* Consistent with the rules of the New York Stock Exchange, all members of the Human Resources Committee are independent.

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.

Audit Committee Disclosure

THE AUDIT COMMITTEE of the Board operates pursuant to a charter and is responsible for, among other things, the appointment of the independent registered public accounting firm for the Company; reviewing with the independent registered public accounting firm 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 internal auditors and the independent registered public accounting firm. 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*. Consistent with the rules of the New York Stock Exchange and the Sarbanes-Oxley Act of 2002, all members of the

Audit Committee are independent. The Board of Directors determined in 2004 that Mr. Kujawa was an audit committee financial expert as defined by the Securities and Exchange Commission. Mr. Kujawa's term as a Director expires at the 2005 annual meeting and he is not standing for reelection. The Board of Directors determined on February 22, 2005 that Mr. Nowell is an audit committee financial expert as so defined.

Audit Committee Report

THE AUDIT COMMITTEE reviews AEP's financial reporting process as well as the internal controls over financial reporting on behalf of the Board of Directors. Management has the primary responsibility for the financial statements and the reporting process, including the system of internal control over financial reporting.

In this context, the Audit Committee met thirteen times during the year and held discussions, some of which were in private, with management, the internal auditors, and the independent registered public accounting firm. 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, 2004. The Audit Committee has reviewed and discussed the consolidated financial statements and internal control over financial reporting with management, the internal auditors, and the independent registered public accounting firm. The Audit Committee discussed with the independent registered public accounting firm matters required to be discussed by Statement on Auditing Standards No. 61, as amended (Communication With Audit Committees).

In addition, the Audit Committee has discussed with the independent registered public accounting firm its independence from AEP and its management, including the matters in the written disclosures required by the Independence Standards Board Standard No. 1 (Independence Discussions With Audit Committees). The Audit Committee has also received written materials addressing the independent registered public accounting firm internal quality control procedures and other matters, as required by the New York Stock Exchange listing standards.

In reliance on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors, 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, 2004, for filing with the Securities and Exchange Commission.

Audit Committee Members
Leonard J. Kujawa, Chair
Lester A. Hudson, Jr.
Lionel L. Nowell, III

Directors Compensation and Stock Ownership Guidelines

Annual Retainers and Meeting Fees. Mr. Morris is the only Director who is an officer of AEP. He does not receive any compensation, other than his regular salary and the accident insurance coverage described below, for serving on AEP's Board of Directors. The other members of the Board receive an annual cash retainer of $60,000. The chairman of the Audit Committee receives an additional annual retainer of $15,000 and other members of the Audit Committee receive an additional annual retainer of $10,000. The Presiding Director receives an additional annual retainer of $15,000. Each of these cash retainers is paid in quarterly increments. In 2004, the members of the ad hoc subcommittee of the Board that conducted an assessment and drafted an environmental report to shareholders received $10,000 (other than the chairman, who received $12,000). Each Non-Employee Director also received $60,000 in AEP Stock Units in 2004 payable quarterly pursuant to the Stock Unit Accumulation Plan described below.

In December 2004, upon the recommendation of the Committee on Directors and Corporate Governance and based on competitive data, the Board of Directors adopted changes to the cash and equity compensation to be paid to members of the Board of Directors. These changes were adopted in order to bring the compensation packages of AEP's Board members more in line with compensation paid to directors of comparable companies and enable AEP to attract qualified Directors when needed.

Effective January 1, 2005, (i) the amount of AEP Stock Units awarded to Non-Employee Directors pursuant to the Stock Unit Accumulation Plan increased from $60,000 to $80,000 annually and (ii) Non-Employee Directors will be paid a fee of $1,200 per day for special assignments (such as attendance at Nuclear Regulatory Commission meetings or for services on future ad hoc subcommittees).

Deferred Compensation and Stock Plan. The Deferred Compensation and Stock Plan for Non-Employee Directors permits non-employee Directors to choose to receive up to 100 percent of their annual Board cash retainer in units that are equivalent in value to shares of AEP Common Stock (AEP Stock Units), deferring receipt by the Non-Employee Director until termination of service or for a period that results in payment commencing not later than five years after termination of service. AEP Stock Units are credited to Directors when the retainer becomes payable, 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. Payments with respect to the accumulated AEP Stock Units are made in cash. In December 2004, the Board approved an amendment to this Plan that will permit Non-Employee Directors to defer their annual Board cash retainer into accounts tracked with reference to any of the investment fund options available to participants in the AEP System Incentive Compensation Deferral Plan, including an AEP stock fund.

Stock Unit Accumulation Plan. In 2004 the Stock Unit Accumulation Plan for Non-Employee Directors awarded $60,000 in AEP Stock Units to each Non-Employee Director. As mentioned earlier in *Directors Compensation and Stock Ownership Guidelines*, this Plan was amended effective January 1, 2005 to increase the annual award to $80,000 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, 2004 through September 1, 2007, has a premium of $29,000. In addition, AEP pays each Non-Employee Director an amount to provide for the federal and state income taxes incurred in connection with the maintenance of this coverage ($582 for 2004).

Central and South West Corporation Memorial Gift Programs. AEP is continuing a memorial gift program for former CSW directors and executive officers who had been previously participating in this program. The four former CSW directors who are members of AEP's Board (Messrs. Brooks, Carlton, Howell and Sandor) are participants. 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 the program. The annual premiums paid by AEP are based on pooled risks and averaged $1,583 per participant for 2004.

Stock Ownership. AEP's Board of Directors considers stock ownership in AEP by management to be of great importance. Such ownership enhances management's commitment to the future of AEP and further aligns their interests with those of AEP's shareholders. For further information as to the guidelines for AEP's executive officers, see the *Human Resources Committee Report on Executive Compensation* below under the caption *Stock Ownership Guidelines.* AEP's Board of Directors also considers stock ownership in AEP by Board members to be important. As noted above in *Directors Compensation and Stock Ownership Guidelines* under the caption *Stock Unit Accumulation Plan*, Non-Employee Directors are required to defer $60,000 (increasing effective January 1, 2005 to $80,000) annually in AEP Stock Units until termination of his or her directorship. As noted below under *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. Nowell, who joined the Board of Directors in July 2004.

Insurance

The Directors and officers of AEP and its subsidiaries are insured, subject to certain exclusions, against losses resulting from any claim or claims made against them while acting in their capacities as Directors and officers. The AEP System companies are also insured, subject to certain exclusions and deductibles, to the extent that they have indemnified their Directors and officers for any such losses. Such insurance, effective January 1, 2005 through March 15, 2006, is provided by: Associated Electric & Gas Insurance Services, Energy Insurance Mutual, Zurich American Insurance Company, National Union Fire Insurance Company of Pittsburgh, PA, Federal Insurance Company, Liberty Mutual Insurance Company, Twin City Fire Insurance Company, Quanta Reinsurance U.S. Ltd., AXIS Reinsurance Company, Starr Excess International, Oil Casualty Insurance, Ltd, Arch Insurance Company, RSUI Indemnity Company, XL Specialty Insurance Company, U.S. Specialty Insurance Company and XL Insurance (Bermuda). The total cost of this insurance is $4,938,942.

Fiduciary liability insurance provides coverage for AEP System companies, 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. This coverage, provided by Federal Insurance Company, Zurich American Insurance Company, Energy Insurance Mutual and Indian Harbor Insurance Company, U.S. Specialty Insurance Company and AXIS Specialty Reinsurance Company, was renewed, effective July 1, 2004 through July 1, 2005, for a cost of $800,000.

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 2005. 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, 2005. 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 shares present in person or by proxy at the meeting.

Your Board of Directors recommends a vote **FOR** this proposal.

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, 2004 and December 31, 2003, and fees billed for other services rendered by Deloitte & Touche LLP during those periods.

	2003	2004
Audit Fees(1)		
Financial Statements	$ 9,970,000	$ 9,489,000
Internal Control over Financial reporting	$ —	$ 6,321,000
Total Audit Fees	$ 9,970,000	$15,810,000
Audit-Related Fees(2)	$ 1,347,000	$ 818,000
Tax Fees(3):		
Settlement of Contingent Fee arrangements	$ —	$ 6,962,500
Other tax fees	$ 3,477,000	$ 1,554,500
Total Tax Fees	$ 3,477,000	$ 8,517,000
All Other Fees(4)	$ 115,000	$ —
TOTAL	$14,909,000	$25,145,000

(1) Audit fees in 2003 and 2004 consisted primarily of fees related to the audit of the Company's annual consolidated financial statements. In 2004, 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 2 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, such as attestation requirements on statutory reports and regulatory filings of the Company and certain of its wholly owned subsidiaries.

(2) Audit related fees consisted principally of audits of employee benefit plans and audits in connection with dispositions.

(3) Other 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.

In May 2004, the SEC clarified its position on the provision of services with respect to contingent, findings-based and value-added fee arrangements. In response to this clarification the Company converted five contingent fee arrangements, previously entered into in 2000, to "time and material" fee arrangements and made a payment of $6,962,500 for services performed through May 2004. The Company will not enter into such arrangements with the independent registered public accounting firm in the future. These services are considered tax compliance services based on the above definition.

(4) All other fees in 2003 consisted principally of work performed in preparation of the Sarbanes-Oxley Act Section 404 attestation requirements which became effective for the first time in 2004.

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.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accounting Firm

The Audit Committee's policy is to pre-approve all audit and non-audit services provided by the independent registered public accounting firm. 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 registered public accounting firm and management are required to report to the Audit Committee at each regular meeting regarding the extent of services provided by the independent registered public accounting firm 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 2004, all Deloitte & Touche LLP services were pre-approved by the Audit Committee.

3. Approval of Amended and Restated AEP System 2000 Long-Term Incentive Plan

THE AMERICAN ELECTRIC Power System 2000 Long-Term Incentive Plan (2000 Plan) was approved by AEP's shareholders at the 2000 annual meeting. The purpose of the 2000 Plan is to promote the interests of AEP and its shareholders by strengthening AEP's ability to attract, motivate and retain employees and Directors, to align further the interests of AEP's management with the shareholders, and to provide an additional incentive for employees and Directors to promote the financial success and growth of AEP. The aggregate number of shares currently reserved for issuance under the 2000 Plan is 15,700,000 shares, of which 3,754,150 remain available for awards.

The 2000 Plan allows the grant of incentive awards to employees of the AEP System and to nonemployee members of the Board of Directors. The 2000 Plan provides for the grant of stock options, including incentive stock options and nonqualified stock options, stock appreciation rights, restricted stock, performance share awards, phantom stock, and dividend equivalents, as described below.

The Board of Directors approved at its meeting on February 22, 2005 and is now asking shareholders to vote on and approve amendments to the 2000 Plan (the 2000 Plan, as so amended, the Plan). Amendments requiring shareholder approval are (i) the provision of an additional 15,445,850 shares of AEP Common Stock for awards under the Plan, which, when added to 3,754,150 shares currently available (as of February 22, 2005), establishes a new limit of 19,200,000 shares of AEP Common Stock available for new awards under the Plan (the Plan also establishes a limit of 9 million shares of AEP Common Stock for new full value share awards which includes all awards other than stock options and cash settled or paid stock appreciation rights); (ii) an increase in the maximum number of options and stock appreciation rights that may be awarded to a participant during any three calendar year period from 1,650,000 to 2,000,000 each; (iii) an increase in the maximum number of restricted shares that may be awarded to a participant during any one calendar year from 330,000 to 400,000; (iv) an increase in the maximum amount of compensation that may be payable to a participant during any one calendar year under a performance-based award from $8,260,000 to $15,000,000; (v) an increase in the maximum number of performance share units that may be earned by a participant during any one calendar year from 330,000 to 400,000; and (vi) the revised performance criteria under the Plan.

The Plan is designed to allow for the grant of certain types of awards that conform to the requirements for tax deductible "performance-based" compensation under Section 162(m) of the Internal Revenue Code, as discussed under *Tax Policy on Deductibility of Executive Compensation* in the section of this proxy statement entitled *Human Resources Committee Report on Executive Compensation*. Shareholder approval of the Plan is also requested in order to maximize the deductibility of the payments under the Plan to AEP's chief executive officer and other four most highly compensated officers under the provisions of Section 162(m), and to comply with the requirements of the regulations issued by the Internal Revenue Service governing the deductibility of individual compensation amounts in excess of $1,000,000.

The Human Resources Committee (HR Committee) expects to consider approximately 550 employees for participation in the Plan each year. The number of persons eligible to participate in the Plan and the number of grantees may vary from year to year.

The closing price of AEP's Common Stock on March 1, 2005, was $33.71 per share.

Performance Criteria

The Board of Directors amended and restated the performance criteria upon which the payment or vesting of a performance award may be based. As amended and restated, the performance criteria available to the HR Committee under the Plan include:

- earnings measures (including, for example, primary earnings per share, fully diluted earnings per share, ongoing earnings per share, net income, pre-tax income, operating income, earnings before interest, taxes, depreciation and amortization or any combination thereof, and net operating profits after taxes);
- expense control (including, for example, operations & maintenance expense, total expenditures, expense ratios, and expense reduction);
- customer measures (including, for example, customer satisfaction, service cost, service levels, responsiveness, bad debt collections or losses, and reliability—such as outage frequency, outage duration, and frequency of momentary outages);
- safety measures (including, for example, recordable case rate, severity rate, and vehicle accident rate);
- diversity measures (including, for example, minority placement rate and utilization);
- environmental measures (including, for example, emissions, project completion milestones, regulatory/legislative/cost recovery goals, and notices of violation);
- revenue measures (including, for example, revenue and margin);
- shareholder return measures (including, for example, total shareholder return, economic value added, cumulative shareholder value added, return on equity, return on capital, return on assets, dividend payout ratio and cash flow(s)—such as operating cash flows, free cash flow, discounted cash flow return on investment and cash flow in excess of cost of capital or any combination thereof);
- valuation measures (including, for example, stock price increase, price to book value ratio, and price to earnings ratio);
- capital and risk measures (including, for example, debt to equity ratio, dividend payout as percentage of net income and diversification of business opportunities);
- employee satisfaction;
- project measures (including, for example, completion of key milestones);
- production measures (including, for example, generating capacity factor, performance against the Institute of Nuclear Power Operation index, generating equivalent availability, heat rates and production cost); and
- such other individual performance objective that is measured solely in terms of quantitative targets related to AEP or any subsidiary or AEP's or any such subsidiary's business.

Summary of the Plan

The full text of the Plan is set forth in Exhibit A to which reference is made. The following description of certain features of the Plan is qualified in its entirety by this reference.

Reservation of Shares. AEP has reserved, subject to shareholder and SEC approval of the Plan, 19,200,000 total shares of AEP Common Stock for issuance under the Plan. This includes 3,754,150 shares of AEP Common Stock that are currently available for awards under the 2000 Plan and 15,445,850 newly authorized shares of AEP Common Stock. The shares to be delivered under the Plan will be made available from authorized but unissued shares and/or shares reacquired by AEP. If any shares of AEP Common Stock that are the subject of an award are not issued and cease to be issuable for any reason, such shares will no longer be charged against such maximum share limitation and may again be made subject to awards under the Plan. In the event of certain corporate reorganizations, recapitalizations, or any similar corporate transactions affecting AEP or AEP Common Stock, or stock splits, stock dividends or other distribution with respect to AEP Common Stock, proportionate adjustments may be made to the number of shares available for grant under the Plan, the applicable maximum share limitations under the Plan, and the number of shares and exercise prices of outstanding awards at the time of the event.

Administration. The Plan will be administered by the HR Committee. Subject to the limitations set forth in the Plan, the HR Committee has the authority to determine the persons to whom awards are granted, the types of awards to be granted, the time at which awards will be granted, the number of shares, units or other rights subject to each award, the exercise, base or purchase price of an award (if any), the time or times at which the award will become vested, exercisable or payable, and the duration of the award. The HR Committee may provide for the acceleration of the vesting period and the extension of the exercise period of an award at any time prior to its termination or upon the occurrence of specified events. With the consent of the affected participant, the HR Committee has the authority to cancel and replace awards previously granted with new awards for the same or a different number of shares and for the same or different exercise or base price and may amend the terms of any outstanding award, provided that the HR Committee shall not have the authority to reduce the exercise or base price of an award by amendment or cancellation and substitution of an existing award without approval of AEP's shareholders. With respect to awards granted under the Plan to nonemployee members of the Board of Directors, all rights, powers and authorities vested in the HR Committee under the Plan shall instead be exercised by the Board.

Eligibility. All employees of AEP and its subsidiaries and all nonemployee members of the Board of Directors are eligible to be granted awards under the Plan, as selected from time to time by the HR Committee in its sole discretion.

Stock Options. The Plan authorizes the grant of nonqualified stock options and incentive stock options. Nonqualified stock options may be granted to employees and Non-Employee Directors. Incentive stock options may only be granted to employees. The exercise price of an option may be determined by the HR Committee, provided that the exercise price per share of an option may not be less than 100% of the fair market value of a share of AEP Common Stock on the date of grant. Stock options may be granted for any term specified by the HR Committee and the HR Committee may accelerate the exercisability of any option at any time. Under the Plan, the exercise price of an option is payable by the participant in cash, or, at the discretion of the HR Committee, in shares of AEP Common Stock, or by any other method approved of by the HR Committee. The terms of any Incentive Stock Option shall comply with the provisions of the Internal Revenue Code. The maximum number of shares of AEP Common Stock that may be granted under stock options to any one participant during any three calendar year period shall be limited to 2,000,000 shares. Nonqualified stock options granted under the Plan are intended to qualify for exemption under Section 162(m) of the Internal Revenue Code.

Stock Appreciation Rights. The Plan authorizes the HR Committee to grant awards of stock appreciation rights. A stock appreciation right entitles the holder, upon exercise, to receive a payment based on the difference between the base price of the stock appreciation right and the fair market value of a share of AEP Common Stock on the date of exercise, multiplied by the number of shares as to which such stock appreciation right will have been exercised. A stock appreciation right may be granted either in tandem with an option or without relationship to an option. A stock appreciation right granted in tandem with an option will have a base price per share equal to the per share exercise price of the option, will be exercisable only at such time or times as the related option is exercisable and will expire no later than the time when the related option expires. Exercise of the option or the stock appreciation right as to a number of shares results in the cancellation of the same number of shares under the tandem right. A stock appreciation right granted without relationship to an option will be exercisable as determined by the HR Committee. The base price assigned to a stock appreciation right granted without relationship to an option shall not be less than 100% of the fair market value of a share of AEP Common Stock on the date of grant. The maximum number of shares of AEP Common Stock that may be subject to stock appreciation rights granted to any one participant during any three calendar year period shall be limited to 2,000,000 shares. Stock appreciation rights are payable in cash, in restricted or unrestricted shares of AEP Common Stock, or a combination thereof, in the discretion of the HR Committee. Any shares of AEP Common Stock used to settle or pay stock appreciation rights will be counted as full value shares. Stock appreciation rights granted under the Plan are intended to qualify for exemption under Section 162(m) of the Internal Revenue Code.

Performance Awards. The Plan authorizes the HR Committee to grant performance awards, which are units denominated on the date of grant either in shares of AEP Common Stock (performance shares) or in specified dollar amounts (performance units). Performance awards are payable upon the achievement of performance criteria established by the HR Committee at the beginning of the performance period. At the time of grant, the HR Committee establishes the number of units, the duration of the performance period or periods, the applicable performance criteria, and, in the case of performance units, the target unit value or range of unit values for the performance awards. At the end of the performance period, the HR Committee determines the payment to be made based on the extent to which the performance goals have been achieved. Performance awards are payable in cash, restricted or unrestricted shares of AEP Common Stock, phantom stock or options, or a combination thereof, in the discretion of the HR Committee.

The HR Committee may grant performance awards that are intended to qualify for exemption under Section 162(m) of the Internal Revenue Code, as well as performance awards that are not intended to so qualify. A Section 162(m) qualified award may relate to AEP, any subsidiary or any business unit, may be measured on an absolute or relative-to-peer-group basis, and must be based upon the performance criteria stated above under *Performance Criteria*.

The HR Committee may at any time before payment reduce the number of performance awards earned by any participant for a performance period. The maximum amount of compensation that may be payable in any one calendar year to any one participant designated to receive a performance unit award intended to qualify under Section 162(m) is $15,000,000. The maximum number of performance share units that may be earned in any one calendar year by any one participant that is intended to qualify under Section 162(m) is 400,000 units.

Restricted Stock. The Plan authorizes the HR Committee to make awards of restricted stock. An award of restricted stock represents shares of AEP Common Stock that are issued subject to such restrictions on transfer and on incidents of ownership and such forfeiture conditions as the HR Committee deems appropriate. The restrictions imposed upon an award of restricted stock will lapse in accordance with the vesting requirements specified by the HR Committee in the award agreement. Such vesting requirements may be based on the continued employment of the participant for a specified time period or on the attainment of specified business goals or performance criteria established by the HR Committee. Subject to the transfer restrictions and forfeiture restrictions relating to the restricted stock award, the participant will otherwise have the rights of a shareholder of AEP, including all voting and dividend rights, during the period of restriction unless the HR Committee determines otherwise at the time of the grant.

The HR Committee may grant awards of restricted stock that are intended to qualify for exemption under Section 162(m) of the Internal Revenue Code, as well as awards that are not intended to so qualify. An award of restricted stock that is intended to qualify for exemption under Section 162(m) shall have its vesting requirements limited to the performance criterion mentioned above under the heading *Performance Criteria*. The maximum number of shares of AEP Common Stock that may be subject to awards of restricted stock intended to qualify under Section 162(m) granted to any one participant during any calendar year shall be limited to 400,000 shares.

Phantom Stock. The Plan authorizes the HR Committee to grant awards of phantom stock. An award of phantom stock gives the participant the right to receive payment at the end of a fixed vesting period based on the value of a share of AEP Common Stock at the time of vesting. Phantom Stock Units are subject to such restrictions and conditions to payment as the HR Committee determines are appropriate. An award of phantom stock may be granted, at the discretion of the HR Committee, together with an award of dividend equivalent rights for the same number of shares covered thereby. Phantom stock awards are payable in cash, restricted or unrestricted shares of AEP Common Stock, options, or a combination thereof, at the discretion of the HR Committee.

The same conditions and limitations applicable to restricted stock awards are also applicable to phantom stock awards that are intended to qualify for exemption under Section 162(m).

Dividend Equivalents. The Plan authorizes the HR Committee to grant awards of dividend equivalents. Dividend equivalent awards entitle the holder to a right to receive cash, shares of AEP Common Stock, or other property equal in value to dividends paid with respect to a specified number of shares of AEP Common Stock. Dividend equivalents may be awarded on a free-standing basis or in connection with another award, and may be paid currently or on a deferred basis. The HR Committee may provide at the date of grant or thereafter that the dividend equivalent award shall be paid or distributed when accrued or shall be deemed to have been reinvested in additional shares of AEP Common Stock, or other investment vehicles as the HR Committee may specify, provided that dividend equivalent awards (other than free-standing dividend equivalent awards) shall be subject to all conditions and restrictions of the underlying awards to which they relate.

Change in Control. The HR Committee may provide for the effect of a "change in control" (as defined in the Plan) upon an award granted under the Plan. Such provisions may include:

- The acceleration or extension of time periods for purposes of exercising, vesting in, or realizing gain from an award;
- The waiver or modification of performance or other conditions related to payment or other rights under an award;
- Providing for the cash settlement of an award for an equivalent cash value; or
- Such other modification or adjustment to an award as the HR Committee deems appropriate.

Term and Amendment. The Plan has no fixed expiration date but no award may be granted after April 26, 2015. The HR Committee will establish expiration and exercise dates on an award-by-award basis. The Board may amend the Plan at any time, except that shareholder approval is required for amendments that would either (i) increase the number of shares of AEP Common Stock reserved for issuance under the Plan or (ii) allow the grant of options at an exercise price below fair market value or (iii) allow the repricing of options.

Federal Income Tax Consequences. The following is a general description of the federal income tax consequences to participants and AEP relating to options and other awards that may be granted under the Plan based on present tax law. This discussion does not purport to cover all tax consequences relating to options and other awards.

A participant will not recognize income upon the grant of a nonqualified stock option to purchase shares of AEP Common Stock. Upon exercise of the option, the participant will recognize ordinary compensation income equal to the excess of the fair market value of the shares of AEP Common Stock on the date the option is exercised over the exercise price for such shares. AEP will be entitled to a deduction equal to the amount of ordinary compensation income recognized by the participant. The deduction will be allowed at the same time that the participant recognizes the income.

A participant will not recognize income upon the grant of an incentive stock option to purchase shares of AEP Common Stock and will not recognize income upon exercise of the option, provided the participant was an employee of the AEP System at all times from the date of grant until three months prior to exercise. Where a participant who has exercised an incentive stock option sells the shares of AEP Common Stock acquired upon exercise more than two years after the grant date and more than one year after exercise, capital gain or loss will be recognized equal to the difference between the sales price and the exercise price. A participant who sells such shares of AEP Common Stock within two years after the grant date or within one year after exercise will recognize ordinary compensation income in an amount equal to the difference between the fair market value of such shares on the date of exercise (that is, the sales proceeds excluding any brokerage fees or other costs paid in connection with the disposition) and the exercise price. Any remaining gain or loss will be treated as a capital gain or loss. AEP will be entitled to a deduction equal to the amount of ordinary compensation income recognized by the optionee in this case. The deduction will be allowable at the same time that the participant recognizes the income.

Except as otherwise specified under Section 409A of the Internal Revenue Code, the current federal income tax consequences of other awards authorized under the Plan are generally in accordance with the following: stock appreciation rights are subject to taxation in substantially the same manner as nonqualified stock options; restricted stock subject to a substantial risk of forfeiture results in income recognition only at the time the restrictions lapse (unless the recipient elects to accelerate recognition as of the date of grant); performance awards, phantom stock and dividend equivalents are generally subject to tax at the time of payment. In each of the foregoing cases, AEP will generally have a corresponding deduction at the same time that the participant recognizes income.

Section 409A was added to the Internal Revenue Code by the American Jobs Creation Act of 2004 and generally affects amounts deferred under a covered nonqualified deferred compensation plan after December 31, 2004, and such prior deferrals under a plan that has been materially modified after October 3, 2004. Section 409A provides that covered amounts deferred under a nonqualified deferred compensation plan are includable in the participant's gross income to the extent not subject to a substantial risk of forfeiture and not previously included in income, unless certain requirements are met, including limitations on the timing of deferral elections and events that may trigger the distribution of deferred amounts. Preliminary guidance issued under Code Section 409A suggests that certain types of awards under the Plan (other than incentive stock options) may be subject to the additional limitations. The Board intends to further review the terms of the Plan and awards made under the Plan and may adopt such additional amendments as it determines appropriate in light of the current and any additional guidance issued under Code Section 409A.

Equity Compensation Plan Information

All of AEP's equity compensation plans (as defined by applicable SEC regulations) have been approved by its shareholders. AEP's equity compensation plan information as of December 31, 2004 is as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders(1)	8,228,592	$33.29	4,757,247
Equity compensation plans not approved by security holders	0	N/A	0
Total	8,228,592	$33.29	4,757,247

(1) Consists of shares to be issued upon exercise of outstanding options granted under the American Electric Power System 2000 Long-Term Incentive Plan and the CSW 1992 Long-Term Incentive Plan (CSW Plan). The CSW Plan was in effect prior to the consummation of the AEP-CSW merger. All unexercised options granted under the CSW Plan were converted into options to purchase 0.6 AEP common shares, vested on the merger date and will expire ten years after their grant date. No additional options will be issued under the CSW Plan.

Vote Required.

Approval of this proposal requires the affirmative vote of holders of a majority of the shares of AEP Common Stock present in person or by proxy at the meeting.

Your Board of Directors recommends a vote **FOR** approval of the Amended and Restated American Electric Power System 2000 Long-Term Incentive Plan.

4. Shareholder Proposal

A SHAREHOLDER, the AFL-CIO Reserve Fund, 815 Sixteenth Street NW, Washington DC 20006, has informed the Company that it intends to present the proposal set forth below at the meeting. The AFL-CIO Fund states that it is the beneficial owner of 200 shares of our Common Stock.

RESOLVED: The shareholders of American Electric Power (the "Company") urge the Board of Directors (the "Board") to seek shareholder approval of any future extraordinary retirement benefits for senior executives. The Board shall implement this policy in a manner that does not violate any existing employment agreement or vested pension benefit.

For the purposes of this resolution, "extraordinary retirement benefits" means receipt of additional years of service credit not actually worked, preferential benefit formulas not provided under the Company's tax-qualified retirement plans, accelerated vesting of pension benefits, and retirement perquisites and fringe benefits that are not generally offered to other Company employees.

Supporting Statement: Supplemental executive retirement plans provide retirement benefits for a select group of management or highly compensated employees whose compensation exceeds limits set by Federal tax law. Because SERPs are unfunded plans and payable out of the Company's general assets, the associated pension liabilities can be significant.

Our Company's SERPs provide executives with additional pension benefits not provided by the Company's tax-qualified retirement plan. Specifically, several of our Company's senior executives have received years of service credit under the Company's SERPs for years not actually worked.

Under their employment agreements, Company Chairman and CEO E. Linn Draper and Vice President Susan Tomasky received 24 and 20 additional years of service pension credit, respectively. In addition, Chief Operating Officer Thomas Shockley will receive approximately 8 extra years of pension service credit and Executive Vice President Thomas Hagan will receive approximately 6 extra years of pension service credit if they remain employed with the Company until age 60.

Providing senior executives with unearned years of service pension credit increases the cost of Company's SERPs to shareholders. In our view, the actuarial present value of an executive's extraordinary retirement benefit can be worth tens of millions of dollars. In addition, we believe these extraordinary pension benefits are unnecessary given the high levels of executive compensation at our Company.

To help ensure that the use of extraordinary pension benefits for senior executives are in the best interests of shareholders, we believe such benefits should be submitted for shareholder approval. Because it is not always practical to obtain prior shareholder approval, the Company would have the option of seeking approval after the material terms were agreed upon.

For these reasons, please vote FOR this proposal.

Directors' Recommendation

Your Board of Directors recommends a vote AGAINST the preceding shareholder proposal for the following reasons:

Our executive compensation program is designed to help AEP compete for the superior talent required to achieve corporate objectives and increase shareholder value. The HR Committee, or, with respect to the compensation program for the CEO, all of the independent members of our Board of Directors (collectively, the Committee) oversees our executive compensation program and approves all compensation arrangements with our executive officers (including employment agreements and retirement benefits). The Committee believes all of AEP's compensation programs are consistent with utility and general industry practice for companies of comparable size and are necessary to attract, motivate, reward and retain talented executives.

The shareholder proposal requests our Board of Directors to seek shareholder approval of certain types of retirement benefits provided under employment agreements and non-qualified retirement programs. Retirement benefits are a critical component of a senior executive's overall compensation program. Removing the flexibility of the Committee to oversee this important aspect of executive compensation would place AEP at a significant competitive disadvantage.

Although the supporting statement for the proposal focuses on retirement benefits in effect for several of the most highly compensated executive officers of AEP last year, the proposal states that the new policy should be implemented "in a manner that does not violate any existing employment agreement or vested pension benefit." The specific retirement benefits objected to in the supporting statement for the proposal are provided for under employment agreements or vested supplemental retirement arrangements. As a result, the shareholder proposal, by its own terms, would only apply to future grants of retirement benefits.

The supporting statement for the proposal asserts that the retirement benefits objected to are "unnecessary given the high levels of executive compensation at our Company..."As noted below in the *Human Resources Committee Report on Executive Compensation*, the salary and bonuses of AEP's executive officers are consistent with AEP's compensation peer group. In order to attract high quality senior management, AEP must have the flexibility to offer the same salary and bonus opportunities and retirement benefits offered by similar companies.

At the 2004 Annual Meeting, only 28.6% of shares voted were in support of a substantially identical proposal. Accordingly, your Board of Directors recommends a vote **AGAINST** this proposal.

Vote Required. Approval of this proposal requires the affirmative vote of holders of a majority of the shares of AEP Common Stock present in person or by proxy at the meeting.

Accordingly, your Board of Directors recommends a vote **AGAINST** this proposal.

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 and the approval of amendments to our Long Term Incentive Plan.

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 enclosed 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.

Executive Compensation

THE FOLLOWING TABLE shows for 2004, 2003 and 2002 the compensation earned by the chief executive officer and the four other most highly compensated executive officers (as defined by SEC regulations) of AEP at December 31, 2004 and Mr. Fayne, who ceased being an executive officer in July, 2004 and resigned on December 31, 2004.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
Name and Principal Position	**Year**	**Salary ($)(1)**	**Bonus ($)(2)**	**Other Annual Compensation $(3)**	**Restricted Stock Award ($)(4)**	**Securities Underlying Options (#)**	**LTIP Payouts $(5)**	**All Other Compensation ($)(6)**
Michael G. Morris — Chairman of the board and chief executive officer of the Company; chairman of the board, president and chief executive officer of AEP and the Service Corporation; chairman of the board and chief executive officer of other AEP System companies(7)	2004	1,123,577	1,250,000	607,553	9,228,000	149,000	-0-	178,058
Susan Tomasky — Executive vice president and chief financial officer of the Company; executive vice president-chief financial officer, assistant secretary and director of the Service Corporation; vice president and director of other AEP System companies	2004	503,846	350,000	-0-	-0-	-0-	-0-	50,791
	2003	476,827	256,137	-0-	-0-	25,000	-0-	37,208
	2002	451,731	49,116	-0-	-0-	88,000	-0-	79,373
Thomas M. Hagan — Executive vice president-AEP Utilities West and director of the Service Corporation; vice president and director of other AEP System companies	2004	443,385	241,684	58,330	-0-	-0-	-0-	141,398
	2003	421,615	237,850	-0-	-0-	25,000	-0-	29,326
	2002	345,517	-0-	-0-	-0-	88,000	-0-	59,976
Holly K. Koeppel — Executive vice president-AEP Utilities East and director of the Service Corporation; vice president and director of other AEP System companies	2004	443,385	267,217	2,404	-0-	-0-	-0-	37,304
	2003	426,635	175,000	-0-	-0-	25,000	-0-	25,451
	2002	267,279	250,000	-0-	-0-	88,000	-0-	109,751
Robert P. Powers — Executive vice president-Generation and director of the Service Corporation; vice president and director of other AEP System companies	2004	433,308	275,000	654	-0-	-0-	-0-	34,879
	2003	416,596	300,000	-0-	-0-	25,000	-0-	29,007
	2002	401,539	49,116	-0-	-0-	88,000	-0-	68,853
Henry W. Fayne — (retired) Executive vice president and director of the Service Corporation; vice president and director of other AEP System companies(8)	2004	518,961	309,000	-0-	-0-	-0-	-0-	970,895
	2003	501,923	256,225	-0-	-0-	25,000	-0-	39,150
	2002	481,846	49,116	-0-	-0-	88,000	-0-	80,830

(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 workdays and holidays.

(2) Amounts in the *Bonus* column reflect awards under the Senior Officer Annual Incentive Compensation Plan (SOIP) for 2003 and 2004, except for Mr. Fayne whose 2004 bonus was paid as part of a severance agreement. Payments pursuant to the SOIP are made in the first quarter of the succeeding fiscal year for performance in the year indicated. No SOIP

awards were made for 2002, but Messrs. Powers and Fayne and Ms. Tomasky received payments of $49,116 each in February 2002 in recognition of their efforts in connection with a management reorganization. The amount in the Bonus column for Ms. Koeppel in 2002 represents a payment for successfully completing the sale of certain international investments.

(3) Amounts shown in *Other Annual Compensation* include perquisites if the aggregate amount of such benefits exceeds $50,000. For Mr. Morris, the amount shown for 2004 includes the incremental cost associated with his personal use of the Company's airplane of $250,487 and premiums for life insurance that the Company funds on his behalf of $141,403. The *Other Annual Compensation* also includes tax gross-up payments for Mr. Morris and the other named executive officers.

(4) Mr. Morris received an award of 300,000 restricted shares granted under the Company's 2000 Long-Term Incentive Plan upon his employment with AEP. The award was made on January 2, 2004. 50,000 shares vested on January 1, 2005 and 50,000 shares vest on January 1, 2006. The remaining 200,000 shares of restricted stock were granted as a replacement for certain long-term compensation that Mr. Morris forfeited from his prior employer in order to accept his position at AEP. These shares vest, subject to his continued employment, in three equal components on November 30, 2009, November 30, 2010 and November 30, 2011, respectively. The value of the restricted stock as of December 31, 2004 ($10,302,000) is determined by multiplying the total number of shares held by the closing price of AEP Common Stock on the New York Stock Exchange on December 31, 2004. Dividends are paid on all restricted shares at the same rate as paid on AEP's Common Stock.

(5) Amounts in the *Long-Term Compensation — Payouts* column generally reflect phantom stock units resulting from performance share units issued under the AEP 2000 Long-Term Incentive Plan. However, no shares were earned under this or any other plan in the periods shown. The December 10, 2003 through December 31, 2004 performance period did result in an award score of 123.1% of the target award and accrued dividends. However, these shares have not vested and will not generally vest until December 31, 2006, subject to the participant's continued employment. Therefore, the payout for these performance shares will be reported for 2006 if and when they vest. See below under *Long-Term Incentive Plans — Awards in 2004* and page 26 for additional information.

(6) Amounts in the *All Other Compensation column* for 2004, except for additional compensation to Messrs. Morris and Fayne disclosed in footnotes (7) and (8), include (i) AEP's matching contributions under the AEP Retirement Savings Plan and the AEP Supplemental Retirement Savings Plan, a non-qualified plan designed to supplement the AEP Retirement Savings Plan; (ii) relocation and temporary living expenses and (iii) subsidiary companies' director fees. Detail of the 2004 amounts included in the *All Other Compensation* column is shown below.

Item	Mr. Morris	Ms. Tomasky	Mr. Hagan	Ms. Koeppel	Mr. Powers	Mr. Fayne
Savings Plan Matching Contributions	$ 6,534	$ 6,888	$ 8,850	$ 9,225	$ 7,283	$ 6,793
Supplemental Savings Plan Matching Contributions	41,712	27,103	21,626	18,429	16,546	27,892
Relocation and Temporary Living Expenses	27,250	-0-	101,972	-0-	-0-	-0-
Subsidiary Director Fees	17,400	16,800	8,950	9,650	11,050	16,200

(7) No 2002 or 2003 compensation information is reported for Mr. Morris because he was not an executive officer in those years. Club initiation fees of $85,163 were included in the *All Other Compensation* column for Mr. Morris.

(8) In July 2004, AEP realigned its management team and Mr. Fayne ceased being an executive officer of AEP and was assigned other responsibilities. He left active employment on December 31, 2004 with 31 years of service and, as a result, was paid severance compensation of $814,039 and accrued vacation pay of $105,971 that is included in the *All Other Compensation* column. He also received a bonus of $309,000, which is included in the *Bonus* column.

Option Grants in 2004

Name	Individual Grants: Number of Securities Underlying Options Granted(#)(1)	Percent Of Total Options Granted to Employees In 2004	Exercise or Base Price ($/Sh)	Expiration Date	Grant Date Present Value ($)(2)
M. G. Morris	149,000	100%	$30.76	1-2-2014	902,940
S. Tomasky	-0-	-0-	-0-	—	-0-
T. M. Hagan	-0-	-0-	-0-	—	-0-
H. K. Koeppel	-0-	-0-	-0-	—	-0-
R. P. Powers	-0-	-0-	-0-	—	-0-
H. W. Fayne	-0-	-0-	-0-	—	-0-

(1) Mr. Morris is the only executive officer named in the Summary Compensation Table who was granted options in 2004. Upon his hire, the HR Committee granted 149,000 stock options to Mr. Morris pursuant to his employment agreement. All other executives named in the Summary Compensation Table were granted options in December 2003. Mr. Morris' options were granted on January 2, 2004 and have an exercise price of $30.76, which is equal to the closing price of AEP Common Stock on the New York Stock Exchange on that date. Mr. Morris' options will vest in three approximately equal annual amounts beginning on January 1, 2005. These options also fully vest upon termination due to retirement, death or for such other circumstances as the HR Committee determines warrant vesting and continuation of these options. In the above circumstances, these options will expire on the earlier of five years from the date of termination or death, or the original expiration date. All AEP stock options may also vest as the result of a change-in-control of AEP (see discussion of the *Change-in-Control Agreements* on page 31) and expire upon termination of employment for reasons other than retirement, disability or death, unless the HR Committee determines that circumstances warrant continuation of the options for up to five years. Options are nontransferable.

(2) Value was calculated using the Black-Scholes option valuation model. The actual value, if any, ultimately realized depends on the market value of AEP Common Stock at a future date.

Significant assumptions for the grant on January 2, 2004 are shown below:

Stock Price Volatility	28.17%	Dividend Yield	4.84%
Risk-Free Rate of Return	4.14%	Option Term	7 years

Aggregated Option Exercises in 2004 and Year-end Option Values

Name	Shares Acquired on Exercise(#)	Value Realized ($)	Number of Securities Underlying Unexercised Options at 12-31-04(#)		Value of Unexercised In-The-Money Options at 12-31-04($)*	
			Exercisable	Unexercisable	Exercisable	Unexercisable
M. G. Morris	—	—	—	149,000	-0-	$533,420
S. Tomasky	29,333	206,130	200,000	83,667	-0-	$586,846
T. M. Hagan	—	—	91,833	83,667	$213,544	$586,846
H. K. Koeppel	29,332	182,357	23,700	83,668	-0-	$586,853
R. P. Powers	—	—	139,033	107,267	$213,544	$586,846
H. W. Fayne	29,333	211,178	283,667	—	$586,846	—

* Based on the difference between the closing price of AEP Common Stock on the New York Stock Exchange on December 31, 2004 ($34.34) and the option exercise price. "In-the-money" means the market price of the stock is greater than the exercise price of the option on the date indicated.

Long-Term Incentive Plans — Awards In 2004

Mr. Morris is the only executive officer named in the Summary Compensation Table who received awards in 2004. Pursuant to his employment contract, Mr. Morris was awarded performance share units in January 2004, pursuant to the Company's 2000 Long-Term Incentive Plan. All other executives named in the Summary Compensation Table received awards for the same period of performance in December 2003, which were previously reported in AEP's 2004 Proxy Statement. Although Mr. Morris' individual performance period was less than one year, the performance period measured exceeded one year. Mr. Morris' award is described here and in footnote 5 to the Summary Compensation Table under LTIP Payouts for consistency with the other named executive officers. Performance share units are generally equivalent to shares of AEP Common Stock. Dividends are reinvested in additional performance share units for the same performance and vesting period using the closing price of the AEP Common Stock on the dividend payment date. The value of the performance share unit awards is dependent on the Company's total shareholder return for the applicable performance period relative to the S&P electric utilities, the market price of AEP Common Stock at the end of the performance period, the value of dividends paid during the performance period, the AEP Common Stock price on each dividend payment date and AEP's earnings per share versus a target established by the HR Committee.

The number of common stock equivalent units that may be earned at threshold, target and maximum performance levels, excluding any reinvested dividends, is shown in the table below. The HR Committee may, in its discretion, reduce the number of performance share unit targets otherwise earned. In accordance with the performance goals established for the periods set forth below, the threshold, target and maximum awards are equal to 20%, 100% and 200%, respectively, of the performance share unit awards.

Deferral of earned performance share units into phantom AEP Stock Units (equivalent to shares of AEP Common Stock) is mandatory until the officer has met his or her stock ownership requirements discussed in the *Human Resources Committee Report on Executive Compensation*. Once their stock ownership requirement is met, officers may elect to continue to defer earned performance share units or to receive subsequently earned awards in cash and/or AEP Common Stock.

			Estimated Future Payouts of Performance Share Units Under Non-Stock Price-Based Plan		
Name	Number of Performance Share Units	Performance Period Until Maturation or Payout	Threshold (#)	Target (#)	Maximum (#)
M. G. Morris	119,000	12/10/03 – 12/31/04	23,800	119,000	238,000
S. Tomasky	-0-		-0-	-0-	-0-
T. M. Hagan	-0-		-0-	-0-	-0-
H. K. Koeppel	-0-		-0-	-0-	-0-
R. P. Powers	-0-		-0-	-0-	-0-
H. W. Fayne	-0-		-0-	-0-	-0-

The December 10, 2003 through December 31, 2004 performance period did result in an award score of 123.1% of the target award and accrued dividends. These performance shares will generally vest, subject to the participant's continued employment, on December 31, 2006 and, upon vesting, will be reported in the LTIP Payouts column. As of December 31, 2004, the performance shares awarded for Mr. Morris and the other named executive officers (other than Mr. Fayne) had an estimated value of $5,247,770 and $934,872, respectively. The number of performance shares held by Mr. Fayne for this performance period was reduced by approximately two-thirds upon his retirement. The estimated value of Mr. Fayne's performance shares was $311,601 as of December 31, 2004.

Retirement Benefits

AEP maintains qualified and nonqualified defined benefit ERISA pension plans for eligible employees. The tax-qualified plans are the American Electric Power System Retirement Plan (AEP Retirement Plan) and the Central and South West Corporation Cash Balance Retirement Plan (CSW Cash Balance Plan). The nonqualified plans are the American Electric Power System Excess Benefit Plan (AEP Excess Benefit Plan) (together with the AEP Retirement Plan, the AEP Plans) and the Central and South West Corporation Special Executive Retirement Plan (CSW SERP) (together with the CSW Cash Balance Plan, the CSW Plans), each of which provides (i) benefits that cannot be payable 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 AEP employees. The CSW Plans continue as separate plans for those AEP System employees who were participants in the CSW Cash Balance Plan as of December 31, 2000. Each of the executive officers named in the Summary Compensation Table (other than Mr. Hagan) participates in the AEP Plans. Mr. Hagan participates in the CSW Plans.

The benefit formula generally used to calculate benefit additions under the pension plans for all plan participants (including the executive officers named in the Summary Compensation Table) is a cash balance formula. When the cash balance formula was added to each plan, an opening balance was established for employees then participating under each plan's prior benefit formula (as further described below), using a number of factors as set forth in the appropriate plan. Under the cash balance formula, each participant has an account established (for record keeping purposes only) to which dollar amount credits are allocated each year based on a percentage of the participant's eligible pay. The amount of pay taken into account for the executive officers named in the Summary Compensation Table has been capped at $1,000,000. Effective January 1, 2004, that cap on eligible pay was increased to the greater of $1,000,000 or two times the participant's annual base rate of pay as of the last day of a given year (or, if the participant's employment was terminated during the year, as of the date of such termination of employment). The applicable percentage of eligible pay credited to a participant's account is determined each year by reference to the participant's age and years of vesting service as of December 31 of that year (or as of the participant's termination date, if earlier). The following table shows the applicable percentage used to determine the annual dollar amount credits based on the sum of age and years of service indicated:

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%

All dollar amount balances in the cash balance accounts of participants earn a fixed rate of interest that is also credited annually. The interest rate for a particular year is the Applicable Interest Rate set in accordance with Section 417(e)(3)(A)(ii) of the Internal Revenue Code and is currently the average interest rate on 30-year Treasury securities for the month of November of the prior year. For 2004, the interest rate was 5.12%. Interest continues to be credited as long as the participant's balance remains in the plan.

The CSW SERP also includes a final average pay cash balance formula which provides that the cash balance account of participants who at termination of employment hold the office of Vice President or higher of an employer participating in the CSW Plans will be no less than (i) the sum of the Applicable Percentages from the foregoing table generally for each year that the participant earned credited service under the CSW Cash Balance Plan, multiplied by (ii) the participant's final average pay. "Final average pay" for executive officers generally is the average annual compensation (consisting of the following amounts when paid: wages as reported in the *Salary* column of the Summary Compensation Table and that the portion of the *Bonus* column attributable to the Senior Officer Annual

Incentive Compensation Plan, which is described in the *Human Resources Committee Report on Executive Compensation* under the heading *Annual Incentive*) during the 36 consecutive months of highest pay during the 120 months prior to retirement.

Under the cash balance formula, an amount equal to the vested balance (including tax-qualified and nonqualified benefits) then credited to the account is payable to the participant in the form of an immediate or deferred lump-sum or an annuity or, with respect to the nonqualified benefits, in installments. Benefits under the AEP Plans and the CSW Plans generally do not become vested until the participant has been credited with at least 5 years of service. Mr. Morris has an individual agreement with AEP that provides that Mr. Morris will become vested in the amount credited to his cash balance account at a rate of 20% per year as of each of the first five anniversaries of his commencement date (January 1, 2004).

Benefits (from both the tax-qualified and nonqualified plans) under the cash balance formula are not subject to reduction for Social Security benefits or other offset amounts, except that Ms. Koeppel and Mr. Powers each have an individual agreement which provides that their supplemental retirement benefits are reduced by pension entitlements, if any, from plans sponsored by prior employers. The estimated annual benefit that would be payable as a single life annuity under the cash balance formula (or, with respect to Mr. Hagan, under the CSW Plans' final average pay cash balance formula) to each of the executive officers named in the Summary Compensation Table (other than Henry Fayne) at age 65 is:

Name	Annual Benefit
M. G. Morris	$397,600
S. Tomasky	297,000
T. M. Hagan	117,100
H. K. Koeppel	194,500
R. P. Powers	192,300

These amounts are based on the following assumptions and agreements:

- The amounts shown in the *Salary* column of the Summary Compensation Table are used for calendar year 2004 and all subsequent years, assuming no salary changes. The portion of the *Bonus* column attributable to the Senior Officer Annual Incentive Compensation Plan is used for 2005 and annual incentive awards at the 2004 target level (as further described in the *Human Resources Committee Report on Executive Compensation* under the heading *Annual Incentive* on page 34) are used for all subsequent years beyond 2005.
- Conversion of the lump-sum cash balance to a single life annuity at age 65, based on an interest rate of 4.89% (the Applicable Interest Rate being used by the Plans for 2005) and the 1994 Group Annuity Reserving Table published by the Internal Revenue Service.
- Mr. Morris has an individual agreement with AEP that provides for an opening cash balance account of $2,100,000 as of January 1, 2004 (his employment commencement date) and annual credits at the maximum rate provided under the AEP Plans (currently 8.5%).
- Ms. Tomasky, Ms. Koeppel and Mr. Powers have individual agreements with AEP that credit them with years of service in addition to their years of service with AEP as follows: Ms. Tomasky, 20 years; Ms. Koeppel, 15.25 years; and Mr. Powers, 17 years. That service credit was taken into account in calculating their accrued benefit under the AEP Plans as of December 31, 2000, and therefore was reflected in the amount credited to their opening cash balance account as of January 1, 2001, the date the cash balance formula first became effective. As mentioned above, the agreements for Ms. Koeppel and Mr. Powers provide that their respective supplemental retirement benefits are reduced by pension entitlements, if any, from plans sponsored by prior employers.

Henry Fayne's employment with AEP terminated as of December 31, 2004 and he commenced payment of his retirement benefits as of January 1, 2005. His retirement benefits that became payable from the AEP Plans were determined under the final average pay formula, which is described in the following paragraphs.

In addition, employees who have continuously participated in the AEP Plans since December 31, 2000 remain eligible for a pension benefit using the final average pay formula that was in place before the implementation of the cash balance formula described above. Employees who are eligible for both formulas will receive their benefits under the formula that provides the higher benefit, given the participant's choice of the form of benefit (single life annuity, lump sum, etc.). Participants who remain eligible to receive the final average pay formula will continue to accrue pension benefits under that formula until December 31, 2010, at which time each participant's final average pay benefit payable at the participant's normal retirement age (the later of age 65 or 5 years of service) will be frozen and unaffected by the participant's subsequent service or compensation. After December 31, 2010, each participant's frozen final average pay benefit will be the minimum benefit a participant can receive from the AEP Plans at the participant's normal retirement age.

Final average pay under the AEP Plans is computed using the highest average 36 consecutive months of the salary and bonus earned out of the participant's most recent 10 years of service. The information used to compute the final average pay benefit for executive officers named in the Summary Compensation Table above, other than Mr. Morris (who is not eligible for the final average pay formula under the AEP Plans) and Mr. Hagan (whose final average pay benefits are discussed below in connection with the CSW Plans), is consistent with that shown in the *Salary* column of the Summary Compensation Table and that portion of the *Bonus* column attributable to the Senior Officer Annual Incentive Compensation Plan.

The following table shows the approximate annual annuities that would be payable to executive officers and other management employees under the final average pay formula of the AEP Plans, assuming termination of employment on December 31, 2004 after various periods of service and with benefits commencing at age 65.

AEP Plans Pension Plan Table

Annual Highest Average Earnings	Years of Accredited Service					
	15	20	25	30	35	40
$ 400,000	$ 92,715	$123,620	$154,525	$185,430	$216,335	$242,935
500,000	116,715	155,620	194,525	233,430	272,335	305,585
600,000	140,715	187,620	234,525	281,430	328,335	368,235
700,000	164,715	219,620	274,525	329,430	384,335	430,885
800,000	188,715	251,620	314,525	377,430	440,335	493,535
900,000	212,715	283,620	354,525	425,430	469,335	556,185
1,000,000	236,715	315,620	394,525	473,430	552,335	618,835
1,200,000	284,715	379,620	474,525	569,430	664,335	744,135

The amounts shown in the table are the straight life annuities payable under the final average pay formula of the AEP Plans without reduction for any optional features that may be elected at the participant's expense. Retirement benefits listed in the table are not subject to any further reduction for Social Security or other offset amounts. The retirement annuity is reduced 3% per year for each year prior to age 62 in the event of a termination of employment after age 55 and the participant's election to commence benefits between ages 55 and 62. If an employee terminates employment after age 55 and commences benefits at or after age 62, there is no reduction in the retirement annuity.

Under the AEP Plans, as of December 31, 2004, for the executive officers named in the Summary Compensation Table (except for Mr. Morris and Mr. Hagan), the number of years of service applicable for the final average pay formula were as follows: Ms. Tomasky, 26.5 years; Ms. Koeppel, 19.8 years; Mr. Powers, 22.5 years; and Mr. Fayne, 30.1 years. The years of service for Ms. Tomasky, Ms. Koeppel and Mr. Powers include years of service provided by their respective agreements with AEP as described above in connection with the cash balance formula. The agreements for Ms. Koeppel and Mr. Powers provide that their respective supplemental retirement benefits are reduced by pension entitlements, if any, from plans sponsored by prior employers.

Under the CSW Plans, certain employees who were 50 or over and had completed at least 10 years of service as of July, 1997, remain eligible for benefits under the prior pension formulas that are based on career average pay and final average pay. Of the executive officers named in the Summary Compensation Table, Mr. Hagan is eligible to participate in the CSW Plans and has a choice upon his termination of employment to elect his benefit based on the cash balance formula or the prior pension formulas.

The following table shows the approximate annual annuities that would be payable to employees in certain higher salary classifications under the prior benefit formulas provided through the CSW Plans, assuming termination of employment on December 31, 2004 after various periods of service and with benefits commencing at age 65, and prior to reduction by up to 50 percent of the participant's Social Security benefit.

CSW Plans Pension Plan Table

Highest Average Annual Earnings	Years of Accredited Service			
	15	20	25	30 or more
$ 400,000	$100,000	$133,333	$166,667	$200,000
500,000	125,000	166,667	208,333	250,000
600,000	150,000	200,000	250,000	300,000
700,000	175,000	233,333	291,667	350,000
800,000	200,000	266,667	333,333	400,000
900,000	225,000	300,000	375,000	450,000
1,000,000	250,000	333,333	416,667	500,000
1,200,000	300,000	400,000	500,000	600,000

Under the CSW Plans, the annual normal retirement benefit payable from the final average pay formula is based on 1⅔% of "Average Compensation" times the number of years of credited service (up to a maximum of 30 years), reduced by no more than 50 percent of the participant's age 62 or later Social Security benefit and then adjusted annually based on changes in the consumer price index. "Average Compensation" equals the average annual compensation, reported as *Salary* in the Summary Compensation Table, during the 36 consecutive months of highest pay during the 120 months prior to retirement. Mr. Hagan has an agreement entered into with CSW prior to its merger with AEP under which he is entitled to a retirement benefit that will bring his credited years of service to 30 if he remains employed with AEP until age 60 or thereafter. Mr. Hagan attained age 60 during 2004. Therefore, his years of credited service and age as of December 31, 2004, are 30 and 60.

AEP also made available a voluntary deferred-compensation program in 1986, which permitted certain members of AEP System management to defer receipt of a portion of their salaries. Under this program, a participant was able to annually defer up to 10% of his or her salary over a four-year period, and receive supplemental retirement or survivor benefit payments over a 15-year period. The amount of supplemental retirement payments received is dependent upon the amount deferred, age at the time the deferral election was made, and number of years until the participant retires. Mr. Fayne is the only executive officer named in the Summary Compensation Table who participated in this program. He deferred $9,000 of his salary annually over a four-year period and, as a result of his retirement, he will receive monthly supplemental retirement payments of $4,594 over fifteen years commencing in January 2005.

Employment Agreement

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 actions to terminate it. The Agreement provides that Mr. Morris receives an annual salary of $1,115,000, subject to increase, and will participate in the annual bonus and long-term incentive plans. Mr. Morris is eligible to receive an annual bonus under the Senior Officer Annual Incentive Compensation Plan and his target percentage will be equal to at least 100% of his base salary. The Agreement provides that in his first year, Mr. Morris will receive an annual bonus that in no event is less than the target bonus. The Agreement awarded Mr. Morris a nonqualified stock option grant for 149,000 shares, a performance share grant for 119,000 shares and 100,000 restricted shares as a bonus and an additional 200,000 restricted shares as a replacement for certain long-term compensation that Mr. Morris forfeited from his prior employer in order to accept employment with the Company. One-half of the restricted shares awarded to Mr. Morris as a bonus (50,000 shares) vested on January 1, 2005 and the remaining one-half will vest, subject to his continued AEP employment, on January 1, 2006. The restricted shares awarded to Mr. Morris as a replacement for forfeited compensation will vest, subject to his continued employment, in three approximately equal components of 66,666, 66,667 and 66,667 shares on November 30, 2009, November 30, 2010 and November 30, 2011, respectively. Mr. Morris may use the Company aircraft for personal use. The Company has purchased a universal life insurance policy for Mr. Morris that provides a $3 million death benefit. Mr. Morris was provided an opening balance in the Company's Retirement Plan of $2.1 million, which vests in increments of 20% on each of the first five anniversary dates of his employment. Mr. Morris is credited with the maximum rate permitted under the Retirement Plan (currently at 8.5%) on all eligible earnings up to two times his annual base salary. See above under *Retirement Benefits* for additional information. In the event 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.

Severance Agreements and Change-In-Control Agreements

In January 2005, the Board adopted a policy to seek shareholder approval for any future severance agreement with any senior executive officer of the Company when any such agreement would result in specified benefits provided to the officer in excess of 2.99 times his or her salary and bonus. The policy resulted from Board discussions that began following the April 2004 annual shareholders' meeting, at which a majority of the shareholders who cast votes (although not a majority of the shares outstanding) approved a resolution requesting that the Board consider such a policy. A copy of the policy can be found on our website at *www.AEP.com*.

AEP has change-in-control agreements with all of the executive officers named in the Summary Compensation Table, except for Mr. Fayne. If there is a "change-in-control" of AEP and the executive officer's employment is terminated (i) by AEP without "cause" or (ii) by the officer because of a detrimental change in responsibilities, a required relocation or a reduction in salary or benefits, these agreements provide for:

- Lump sum payment equal to 2.99 times the officer's annual base salary plus target annual incentive under the Senior Officer Annual Incentive Compensation Plan.
- Payment, if required, to make the officer whole for any excise tax imposed by Section 4999 of the Internal Revenue Code.
- Outplacement services and other non-cash severance or separation benefits under the terms of a plan or agreement as may then be available to other employees.

Under these agreements, "change-in-control" means:

- The acquisition by any person of the beneficial ownership of securities representing 25% or more of AEP's voting stock;
- A change in the composition of a majority of the Board of Directors under certain circumstances within any two-year period; or
- Approval by the shareholders of the liquidation of AEP, disposition of all or substantially all of the assets of AEP or, under certain circumstances, a merger of AEP with another corporation.

In addition to the change-in-control agreements described above, the American Electric Power System 2000 Long-Term Incentive Plan authorizes the HR Committee to include change-in-control provisions in award agreements (defined in a manner similar to the change-in-control agreements described above). Such provisions may include one or more of the following: (1) the acceleration or extension of time periods for purposes of exercising, vesting in or realizing gains from any award; (2) the waiver or modification of performance or other conditions related to the payment or other rights under an award; (3) provision for the cash settlement of an award for an equivalent cash value; and (4) modification or adjustment to the award as the HR Committee deems appropriate to protect the interests of participants upon or following a change-in-control. The outstanding award agreements issued to the executive officers contain provisions that accelerate the vesting and exercise dates of unexercised options and that offer a cash settlement upon a change-in-control.

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

Human Resources Committee Report On Executive Compensation

The Human Resources Committee of the Board of Directors (HR Committee) annually reviews AEP's executive compensation in the context of the performance of management and the Company. None of the members of the HR Committee is 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 of Directors in accordance with SEC and NYSE rules. One HR Committee member, Mr. Brooks, retired as Chairman and Chief Executive Officer of Central and South West Corporation in June 2000 following the completion of the AEP-CSW merger, and currently receives non-qualified pension and deferred compensation payments from the Company. As a result Mr. Brooks is not considered to be an outside director for purposes of determining executive compensation pursuant to Section 162(m) of the Internal Revenue Code and he, therefore, abstains from voting on performance-based compensation issues at HR Committee meetings whenever this is necessary in order to preserve the intended tax deductibility of qualified compensation under Section 162(m).

In setting compensation levels, the HR Committee recognizes that AEP's executive officers are charged with managing what is among the largest and most geographically diverse energy companies in a volatile business environment.

AEP's executive compensation is designed to maximize shareholder value, to support the implementation of the Company's business strategy and to improve both corporate and personal performance. The HR Committee's compensation policies supporting these objectives are:

- To pay in a manner that motivates both short- and long-term performance, focuses on meeting specified corporate goals and promotes the long-term interests of shareholders.
- To place a significant amount of compensation for senior executives at risk in the form of variable incentive compensation instead of fixed or base pay, with much of this risk similar to the risk experienced by other AEP shareholders.

- To establish compensation opportunities that enhance the Company's ability to attract, retain, reward, motivate and encourage the development of exceptionally knowledgeable, highly qualified and experienced executives.
- To provide compensation that is reflective of current market practices in order to maintain a stable and successful management team.

In carrying out its responsibilities, the HR Committee has hired a nationally recognized independent consultant to provide information on current trends in executive compensation and benefits within the energy services industry and among U.S. industrial companies in general, and to provide recommendations to the HR Committee regarding AEP's compensation and benefits programs and practices.

The HR Committee annually reviews AEP's executive compensation relative to a Compensation Peer Group comprised of companies that represent the talent markets from which AEP must compete to attract and retain executives. The HR Committee annually reviews and adjusts the composition of the Compensation Peer Group to ensure that it provides appropriate compensation comparisons. For 2004, the Compensation Peer Group consists of 13 large and diversified energy services companies, plus 12 Fortune 500 companies, which, taken as a whole, approximately reflect the Company's size, scale, business complexity and diversity. This Compensation Peer Group differs from the S&P 500 and the S&P Electric Utility indexes, which are used for financial comparison purposes in the graph titled "Comparison of Five Year Cumulative Total Return" on page 38 in this proxy statement. The HR Committee generally uses median compensation information of the Compensation Peer Group as its benchmark but does consider other comparisons, such as industry-specific compensation surveys, when setting pay levels.

Stock Ownership Guidelines

The HR Committee believes that linking a significant portion of an executive's current and potential future net worth to the Company's success, as reflected in the stock price and dividends paid, gives the executive a stake similar to that of the Company's shareholders and further encourages long-term management strategies that benefit shareholders. Therefore, the HR Committee maintains stock ownership targets for senior managers in order to further align executive and shareholder interests. The HR Committee annually reviews the target stock ownership levels for each salary grade and officer level and periodically adjusts these levels as they determine to be appropriate. AEP's target ownership levels are directly related to the officer's corporate position, with the greatest ownership target assigned to the chief executive officer. In 2004, stock ownership targets were assigned for each of the executive officers named in the Summary Compensation Table in an amount of 109,300 shares for the Chief Executive Officer (CEO) and 35,300 for each of the Executive Vice Presidents.

Executives are expected to achieve stock ownership targets within five years of the date each is assigned. Personal AEP stock holdings, restricted stock, and common stock equivalents resulting from performance shares, deferred compensation and balances in the AEP stock fund of the AEP System Retirement Savings Plan and AEP System Supplemental Retirement Savings Plan are included in determining compliance with the stock ownership targets. AEP's ownership targets reflect the minimum total stock ownership each executive is expected to achieve within the specified five-year period and, therefore, all AEP common stock and stock equivalents held by an executive are counted towards all of their ownership targets simultaneously. All performance shares that would otherwise be earned are mandatorily deferred into phantom Stock Units ("career shares"), a common stock equivalent, for participants who have not met their stock ownership targets. Participants are required to hold these career shares until after their AEP employment ends. In addition, executives that have not met a minimum stock ownership target within its associated 5 year window period will be required to (i) defer twenty-five percent (25%) of their annual incentive compensation into AEP phantom Stock Units and (ii) retain all AEP shares realized through AEP stock options exercises, except an amount equal to the exercise costs and tax withholding, until their stock ownership target has been satisfied. Beginning January 1, 2006, the mandatory annual incentive compensation deferral, described in (i) above, will increase to fifty percent (50%).

As of March 1, 2005, Mr. Morris, Ms. Tomasky and Mr. Hagan have each met all of their stock ownership targets. Ms. Koeppel and Mr. Powers have each met the stock ownership target assigned to them before 2004 and are on course to reach the stock ownership target assigned to them in January 2004. See the table on page 39 for actual ownership amounts.

Components of Executive Compensation

Base Salary. When reviewing executive base salaries, the HR Committee considers the pay practices of its Compensation Peer Group; the responsibilities, performance, and experience of each executive officer; reporting relationships; supervisor recommendations; and the relationship of the base salaries of executive officers to the base salaries of other AEP employees. Base salaries are reviewed annually and adjusted, when and as appropriate, to reflect individual and corporate performance and changes within the Compensation Peer Group.

The HR Committee generally targets base salary levels at the median of AEP's Compensation Peer Group. For 2004, base pay represented less than one-quarter of the compensation opportunity for the CEO and less than one-third for the other listed executive officers when annual and long-term incentive compensation is included (assuming target performance levels were achieved). The 2004 base salary levels for the CEO and other executive officers named in the Summary Compensation Table approximated the median of AEP's Compensation Peer Group for the positions each held at the beginning of the year.

Annual Incentive. The primary purpose of AEP's annual incentive compensation is to motivate senior management to meet and exceed annual objectives that are part of the Company's strategic plan for maximizing shareholder value. For 2004, AEP's Senior Officer Incentive Compensation Plan (SOIP) provided a variable, performance-based annual incentive as part of total compensation for executive officers.

SOIP participants are assigned an annual target award expressed as a percentage of their base earnings for the period. For 2004 the HR Committee initially established annual SOIP target awards for the executive officers named in the Summary Compensation Table, other than Mr. Morris, of 60% of salary. The incentive target for Ms. Tomasky was increased to 65% of salary in June 2004 resulting in a weighted average target of 62.8% of salary for the full year. As part of Mr. Morris's employment agreement, the HR Committee established his annual target award at 100% of his salary for 2004 and specified that his bonus for 2004 will not be less than the target amount.

SOIP awards for 2004 were based on the following pre-established performance measures:

- Earnings Per Share (50%),
- Operations and Maintenance Expense vs. Budget (15%), and
- Annual operating goals (35%), which include:
  - Workforce Safety (15%),
  - Workforce Diversity (10%), and
  - Environmental Goals (10%).

Actual awards for 2004 could have varied from 0% to 200% of the target award based on performance. Annual incentive payments are subject to adjustment at the discretion of the HR Committee.

For 2004, the above performance measures produced an aggregate award score of 96.5% of each employee's target award for the SOIP. The amounts earned for 2004 are shown for the executive officers listed in the *Bonus* column of the Summary Compensation Table on page 22.

Long-Term Incentive. The primary purpose of longer-term, equity-based, incentive compensation is to motivate senior managers to maximize shareholder value by linking a portion of their compensation directly to shareholder return.

All AEP long-term incentive (LTI) awards to executive officers are made under the shareholder-approved American Electric

Power System 2000 Long-Term Incentive Plan. This plan provides various types of LTI and performance measures from which the HR Committee may select to provide the most effective incentives to Company management for achievement of the Company's strategies and goals.

In December 2003 the HR Committee made LTI awards in lieu of LTI awards that would normally have been made in January 2004, which were previously reported in AEP's 2004 proxy statement. The HR Committee reverted back to a January award cycle for subsequent LTI awards. As a result of this change in LTI award timing, AEP made no LTI awards in 2004 to the executive officers named in the Summary Compensation Table other than to Mr. Morris who received LTI awards upon his hire in January 2004 pursuant to his employment agreement.

Stock Options

Upon his hire, the HR Committee granted 149,000 stock options to Mr. Morris pursuant to his employment agreement as shown in the Summary Compensation Table on page 22.

Subsequently, the HR Committee stopped issuing new stock option awards as part of its LTI program, in favor of increased utilization of performance shares. The HR Committee believes this change was necessary to reflect changes in AEP's business objectives, external market compensation practices, and the cost-benefit ratio of stock options relative to other alternatives. Therefore, no other stock options were awarded in 2004.

Performance Shares

The HR Committee periodically grants target performance share awards to AEP management. Performance shares were granted in January of 2002 and 2003 each covering the three-year performance period beginning January 1st of that year and generally vesting, subject to the participant's continued employment, at the end of the performance period. Performance shares were also granted in December 2003 covering the performance period of December 10, 2003 through December 31, 2004 and generally vesting, subject to the participant's continued employment, on December 31, 2006. The performance share awards for the 2002-2004 and 2003-2005 performance periods are earned based on AEP's three-year total shareholder return for the performance period measured relative to the S&P electric utility index with at least median performance required to earn the target award. The performance share awards for the December 10, 2003 through December 31, 2004 performance period are earned based on two equally weighted performance measures: total shareholder return for the performance period measured relative to the S&P electric utilities and one-year earnings per share measured relative to a board approved target. The value of performance share awards ultimately earned for a performance period can range from 0%-200% of the target value plus accumulated dividends.

Upon his hire in January 2004 the HR Committee established a target performance share award of 119,000 performance shares for the December 10, 2003 through December 31, 2004 performance period for Mr. Morris pursuant to his employment agreement. No other performance share targets were established in 2004.

Payments of earned performance share awards are initially deferred in the form of phantom Stock Units (equivalent in fair value to shares of AEP Common Stock) until the participant has met his or her stock ownership target. Such deferrals continue until at least the participant's termination of employment. Once participants reach their respective stock ownership target, they may then elect either to defer subsequent awards into AEP's deferred compensation plan, which offers returns equivalent to various market-based investment options including AEP stock equivalents, or to receive further earned performance share awards in cash and/or AEP Common Stock.

AEP's total shareholder return for the 2002-2004 performance period ranked 19th relative to the S&P peer utilities which produced an award score equal to 20% of the performance shares targets originally granted for this performance period plus dividend credits. However, the HR Committee reduced the award score for this performance period to 0% since AEP's total shareholder return for this performance period was both negative and less than the return on comparable U.S. Treasury securities.

AEP's total shareholder return and earnings per share for the December 10, 2003 through December 31, 2004 performance period produced an award score of 123.1% of the performance share targets originally granted for this performance period plus dividend credits. The resulting awards have been made in phantom Stock Units that will generally vest, subject to the participant's continued employment, on December 31, 2006.

A further description of performance share awards is shown under *Long-Term Incentive Plans – Awards in 2004* on page 26.

Restricted Stock

Upon his hire and pursuant to his employment agreement the HR Committee granted 100,000 restricted shares to Mr. Morris as a bonus and an additional 200,000 restricted shares as a replacement for certain long-term compensation from his prior employer that Mr. Morris was required to forfeit in order to accept employment with AEP. These restricted shares are shares of AEP common stock that include dividend and voting rights but that cannot be sold, transferred, pledged or otherwise encumbered until they vest. One-half of the restricted shares awarded to Mr. Morris as a bonus (50,000 shares) vested on January 1, 2005 and the remaining one-half will vest, subject to his continued AEP employment, on January 1, 2006. The restricted shares awarded to Mr. Morris as a replacement for forfeited compensation will vest, subject to his continued employment, in three approximately equal components of 66,666, 66,667 and 66,667 shares on November 30, 2009, November 30, 2010 and November 30, 2011, respectively. The HR Committee believes that granting these restricted shares to Mr. Morris was reasonable, appropriate and necessary in order to ensure his hire and a timely and successful CEO transition, as well as to motivate Mr. Morris to vigorously pursue the interests of shareholders. The dollar value of the restricted shares awarded to Mr. Morris are shown in the Summary Compensation Table on page 22.

No restricted shares were awarded to any other executive officer or other employee in 2004 but the HR Committee did award restricted Stock Units to certain executive officers and other key employees who are not listed in the Summary Compensation Table during 2004.

Tax Policy on Deductibility of Compensation

The HR Committee has considered the impact of Section 162(m) of the Internal Revenue Code, which limits the deductibility of compensation in excess of $1,000,000 paid in any year to the Company's chief executive officer or any of the other four executive officers named in the Summary Compensation Table who are serving as such at the end of the year. The HR Committee's general policy is to structure compensation programs so that Section 162(m) does not limit the tax deductibility of compensation for the Company. The HR Committee also believes that the Company needs flexibility to meet its incentive and retention objectives, even if the Company may not deduct all of its compensation. Performance shares and stock options issued under the American Electric Power System 2000 Long-Term Incentive Plan have been structured to be exempt from the deduction limit because they are made pursuant to a shareholder-approved, performance-driven plan. Annual incentive awards under the SOIP are not eligible for the performance-based exemption because the SOIP has not been designed or implemented in a manner that would comply with the requirements of Section 162(m). The HR Committee believes that it is in the interests of the Company to maintain flexibility to increase annual incentive awards above the amount a strict performance formula might provide. The reservation of such discretion, in itself, precludes the application of the exemption from the Section 162(m) deduction limits.

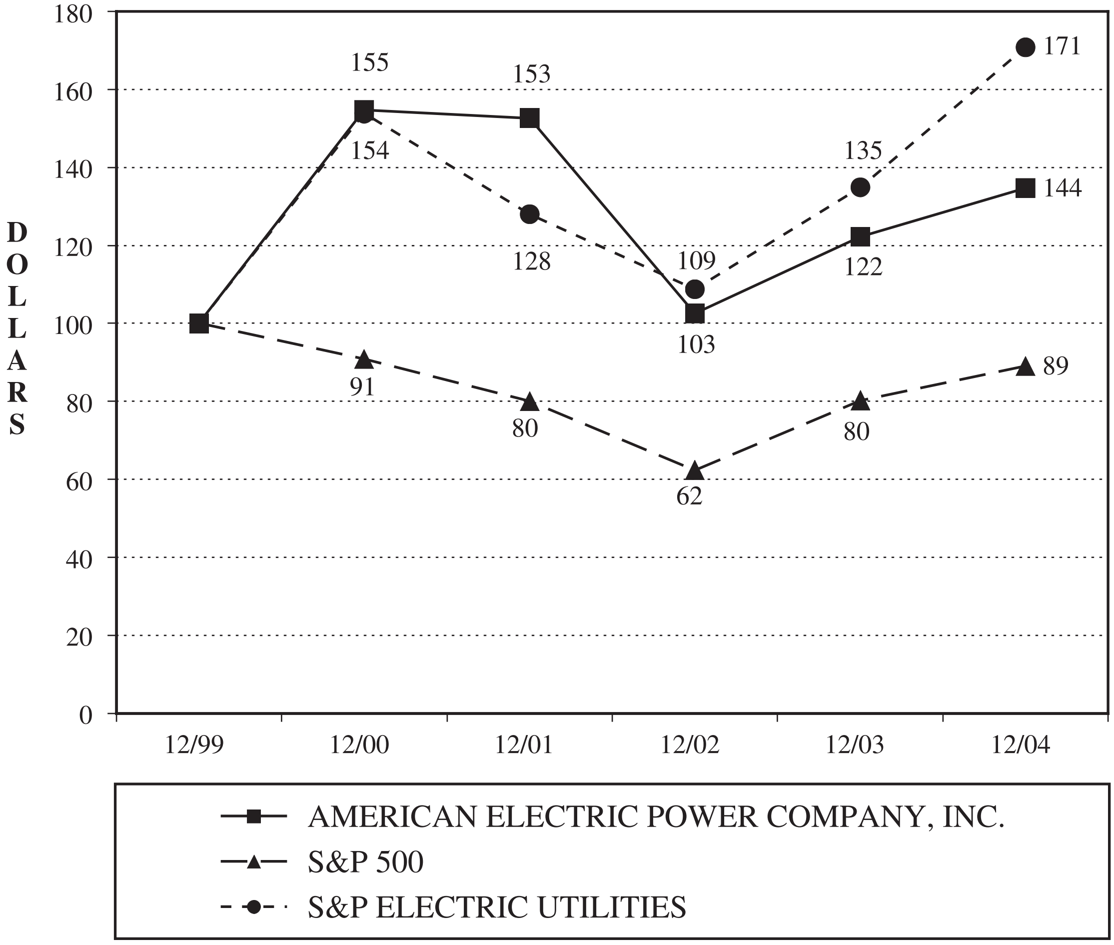
No executive officer named in the Summary Compensation Table, other than Mr. Morris, had taxable compensation paid in 2004 in excess of the Section 162(m) limit. The restricted shares issued to Mr. Morris upon his hire and pursuant to his employment agreement are not performance-based awards and the value of these awards, his 2004 annual bonus and a small portion of his salary, will not be tax deductible to the Company. The HR Committee intends to continue to consider the impact of Section 162(m) in its executive compensation decisions and in evaluating AEP's executive compensation programs.

Human Resources Committee Members
John P. DesBarres, Chair
E. R. Brooks
Donald M. Carlton
Robert W. Fri

Compensation Committee Interlocks and Insider Participation

The HR Committee is composed of Messrs. Brooks, Carlton, DesBarres and Fri. One HR Committee member, Mr. Brooks, retired as Chairman and Chief Executive Officer of Central and South West Corporation in June 2000 following the completion of the AEP-CSW merger. As a result Mr. Brooks is not considered to be an outside director for purposes of determining executive compensation pursuant to Section 162(m) of the Internal Revenue Code and he, therefore, abstains from voting on performance-based compensation issues at HR Committee meetings whenever this is necessary in order to preserve the tax deductibility of Section 162(m) qualified compensation.

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 12/31/99 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

	12/99	12/00	12/01	12/02	12/03	12/04
AEP	100.00	154.66	152.68	102.53	122.25	143.64
S&P 500	100.00	90.89	80.09	62.39	80.29	89.02
S&P Electric Utilities	100.00	153.84	128.03	108.74	134.94	170.78

The total return performance shown on the graph above is not necessarily indicative of future performance.

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 January 1, 2005 for all nominees to the Board of Directors, each of the persons named in the Summary Compensation Table and all such 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 and stock-based units of AEP 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)	Options Exercisable Within 60 Days	Total
E. R. Brooks	21,220	6,998	—	28,218
D. M. Carlton	7,432	6,998	—	14,430
J. P. DesBarres	5,000(c)	10,201	—	15,201
H. W. Fayne	7,129(b)(c)	13,699	283,667	304,495
R. W. Fri	3,000	9,127	—	12,127
T. M. Hagan	15,030(b)	155	129,499	144,684
W. R. Howell	1,692	12,266	—	13,958
L. A. Hudson, Jr.	1,853(e)	11,646	—	13,499
H. K. Koeppel	246(b)	380	61,366	61,992
L. J. Kujawa	2,328	14,893	—	17,221
M. G. Morris	310,921(g)	—	49,666	360,587
L. L. Nowell III	—	911	—	911
R. P. Powers	658(b)(d)	1,345	200,299	202,302
R. L. Sandor	1,092	9,632	—	10,724
D. G. Smith	2,500	9,692	—	12,192
K. D. Sullivan	—	15,545	—	15,545
S. Tomasky	2,668(b)(d)	6,744	237,666	247,078
All directors, nominees and executive officers as a group (20 persons)	475,823(d)(f)	176,180	978,929	1,630,932

(a) This column includes amounts deferred in Stock Units and held under AEP's various director and officer benefit plans.
(b) Includes the following numbers of share equivalents held in the AEP Retirement Savings Plan: Ms. Tomasky, 2,668; Ms. Koeppel, 246; Mr. Fayne, 6,407; Mr. Hagan, 4,537; Mr. Powers, 658; and all directors and executive officers as a group, 22,339.
(c) Includes the following numbers of shares held in joint tenancy with a family member: Mr. DesBarres, 5,000 and Mr. Fayne, 671.
(d) Does not include, for Ms. Tomasky and Mr. Powers, 85,231 shares in the American Electric Power System Educational Trust Fund over which Ms. Tomasky and Mr. Powers share voting and investment power as trustees (they disclaim beneficial ownership). The amount of shares shown for all directors and executive officers as a group includes these shares.
(e) Includes 750 shares held by family members of Dr. Hudson over which he disclaims beneficial ownership.
(f) Represents less than 1.5% of the total number of shares outstanding.
(g) Consists of restricted shares with different vesting schedules and accrued dividends.

Section 16(a) Beneficial Ownership Reporting Compliance

SECTION 16(a) of the Securities Exchange Act of 1934 requires AEP's executive officers and Directors to file initial reports of ownership and reports of changes in ownership of Common Stock of AEP with the Securities and Exchange Commission. 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, 2004, AEP believes that all Section 16(a) filing requirements were met during 2004.

Share Ownership of Certain Beneficial Owners

SET FORTH BELOW are the only persons or groups known to AEP as of December 31, 2004, 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**
Capital Research and Management Company 333 South Hope St. Los Angeles, CA 90071	35,674,180(a)	9.0%
AXA Financial, Inc., 1290 Avenue of the Americas New York, NY 10104	27,030,788(b)	6.8%
Barrow, Hanley, McWhinney & Strauss, Inc. 3232 McKinney Avenue 15th Floor Dallas, TX 75204-2429	21,389,077(c)	5.4%

(a) Based on the Schedule 13G, Capital Research and Management Company, an investment adviser, reported that it has sole dispositive power for 35,674,180 shares.

(b) Based on the Schedule 13G jointly filed with the SEC, AXA Financial, Inc., AXA Assurances I.A.R.D. Mutuelle, AXA Assurances Vie Mutuelle and AXA Courtage Assurance Mutuelle, and AXA reported that they have sole voting power for 14,235,612 shares, shared voting power for 3,136,505 shares, sole dispositive power for 27,019,231 shares and shared dispositive power for 11,558 shares.

(c) Based on the Schedule 13G, Barrow, Hanley, McWhinney & Strauss, Inc. reported that it has sole power to vote 4,248,322 shares, shared voting power for 17,140,755 shares, sole dispositive power for 21,389,077 shares.

Shareholder Proposals and Nominations

To be included in AEP's proxy statement and form of proxy for the 2006 annual meeting of shareholders, any proposal which a shareholder intends to present at such meeting must be received by AEP, attention: John B. Keane, Secretary, at AEP's office at 1 Riverside Plaza, Columbus, OH 43215 by November 15, 2005.

Notice to nominate a director must include your name, address, 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: John B. Keane, Secretary, at AEP's office at 1 Riverside Plaza, Columbus, OH 43215 by November 15, 2005. The 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 2005 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 30, 2006. 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

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. Morrow & Co., Inc. will assist in the solicitation of proxies by AEP for a fee of $12,000, plus reasonable out-of-pocket expenses.

Exhibit A
AMENDED AND RESTATED
AMERICAN ELECTRIC POWER SYSTEM LONG-TERM INCENTIVE PLAN

April 26, 2005

Table of Contents

Amended and Restated American Electric Power System Long-Term Incentive Plan

1. PURPOSE OF THE PLAN

The purpose of the Amended and Restated American Electric Power System Long-Term Incentive Plan, dated April 26, 2005, is to promote the interests of AEP and its shareholders by strengthening AEP's ability to attract, motivate and retain employees and directors of AEP and its Subsidiaries upon whose judgment, initiative and efforts the financial success and growth of the business of AEP largely depend, to align further the interests of AEP's management with the shareholders, and to provide an additional incentive for employees and directors through stock ownership and other rights that promote and recognize the financial success and growth of AEP.

2. DEFINITIONS

Wherever the following capitalized terms are used in this Plan they shall have the meanings specified below:

(a) "AEP" means American Electric Power Company, Inc., a New York corporation, and any successor thereto.

(b) "Award" means an award of an Option, Restricted Stock, Stock Appreciation Right, Performance Award, Phantom Stock or Dividend Equivalent granted under the Plan.

(c) "Award Agreement" means an agreement entered into between AEP and a Participant setting forth the terms and conditions of an Award granted to a Participant.

(d) "Board" means the Board of Directors of AEP.

(e) "Change in Control" shall have the meaning specified in Section 12 hereof.

(f) "Code" means the Internal Revenue Code of 1986, as amended.

(g) "Committee" means the Human Resources Committee of the Board consisting of not less than a sufficient number of Non-Employee Directors so as to qualify the Committee to administer the Plan under Rule 16b-3 and each of whom is an "independent" director as defined in the rules of the New York Stock Exchange. If any member of the Committee does not qualify as an "outside director" for purposes of Section 162(m) of the Code or a Non-Employee Director under Rule 16b-3, the Committee with respect to Awards under the Plan for the chief executive officer and the four most highly compensated officers of AEP (other than the chief executive officer), as such "covered persons" may change from time to time for purposes of Section

162(m), shall consist solely of those Committee members who qualify as "outside directors" and Non-Employee Directors. If fewer than two Committee members qualify as both an "outside director" and a Non-Employee Director, the Board shall appoint one or more other members who do qualify as both "outside directors" and Non-Employee Directors.

(h) "Commission" means the Securities and Exchange Commission.

(i) "Common Stock" means the common stock of AEP, $6.50 par value.

(j) "Date of Grant" means the date on which the Committee makes an Award under the Plan, or such later date as the Committee may specify that the Award becomes effective.

(k) "Effective Date" means the Effective Date of this Plan, as defined in Section 15.1 hereof.

(l) "Dividend Equivalent" means an Award under Section 11 hereof entitling the Participant to receive payments with respect to dividends declared on the Common Stock.

(m) "Eligible Person" means any person who is an Employee or a Non-Employee Director.

(n) "Employee" means any person who is an employee of AEP or any Subsidiary; provided, however, that with respect to Incentive Stock Options, "Employee" means any person who is considered an employee of AEP or any Subsidiary for purposes of Section 421 of the Code and the applicable regulations issued thereunder.

(o) "Exchange Act" means the Securities Exchange Act of 1934, as amended from time to time, or any successor statute.

(p) "Fair Market Value" means, as of any applicable date, the closing price per share of the Common Stock as quoted in the New York Stock Exchange—Composite Transactions listing in *The Wall Street Journal* (or such other reliable publication as the Committee, in its discretion, may determine to rely upon) for the date as of which Fair Market Value is to be determined. If there are no sales on such date, then Fair Market Value shall be the closing price per share of the Common Stock as so quoted on the nearest date before the date as of which Fair Market Value is to be determined on which there are sales. If the Common Stock is not listed on the New York Stock Exchange on the date as of which Fair Market Value is to be determined, the Committee shall determine in good faith the Fair Market Value in whatever manner it considers appropriate. Fair Market Value shall be determined without regard to any restriction other than a restriction that, by its terms, will never lapse.

(q) "Full Value Share Award" means an award of Restricted Stock, a Performance Award denominated in shares or units of Common Stock, Phantom Stock, Dividend Equivalents or Stock Appreciation Rights settled or paid in shares of Common Stock.

(r) "Incentive Stock Option" means an option to purchase Common Stock that is intended to qualify as an incentive stock option under Section 422 of the Code, or any successor provision thereto.

(s) "Non-Employee Director" means a member of the Board who is a "non-employee director" as defined in Rule 16b-3 promulgated by the Commission pursuant to the Exchange Act.

(t) "Nonqualified Stock Option" means an option to purchase Common Stock that is not an Incentive Stock Option.

(u) "Option" means an Incentive Stock Option or a Nonqualified Stock Option granted under Section 6 hereof.

(v) "Participant" means any Eligible Person who holds an outstanding Award under the Plan.

(w) "Performance Award" means an Award made under Section 9 hereof entitling a Participant to a payment based on the Fair Market Value of Common Stock (a "Performance Share") or based on specified dollar units (a "Performance Unit") at the end of a performance period if certain conditions established by the Committee are satisfied.

(x) "Phantom Stock" means an Award under Section 10 hereof entitling a Participant to a payment based on a measure of value expressed as a share of Common Stock ("Phantom Stock Unit"). No stock certificates shall be issued with respect to such Phantom Stock Units, but AEP shall maintain a bookkeeping account in the name of the Participant to which the Phantom Stock Units shall relate.

(y) "Plan" means the Amended and Restated American Electric Power System Long-Term Incentive Plan, dated April 26, 2005, as set forth herein, as it may be amended from time to time.

(z) "Plan Year" means AEP's fiscal year, which at the date hereof is the calendar year.

(aa) "Restricted Stock" means an Award under Section 8 hereof entitling a Participant to shares of Common Stock that are nontransferable and subject to forfeiture until specific conditions established by the Committee are satisfied.

(bb) "Rule 16b-3" means Rule 16b-3 promulgated by the Commission pursuant to the Exchange Act, or any successor or replacement rule adopted by the Commission

(cc) "Section 162(m)" means Section 162(m) of the Code and the Treasury Regulations thereunder.

(dd) "Section 162(m) Participant" means any Participant who, in the sole judgment of the Committee, could be treated as a "covered employee" under Section 162(m) at the time income may be recognized by such Participant in connection with an Award that is intended to qualify for exemption under Section 162(m).

(ee) "Stock Appreciation Right" or "SAR" means an Award under Section 7 hereof entitling a Participant to receive an amount, representing the difference between the base price per share of the right and the Fair Market Value of a share of Common Stock on the date of exercise.

(ff) "Subsidiary" means any corporation (other than AEP) in an unbroken chain of corporations beginning with AEP if, at the time of granting an Award, each of the corporations, other than the last corporation in the unbroken chain, owns stock possessing 50 percent or more of the total combined voting power of all classes of stock in one of the other corporations in such chain.

3. SHARES OF COMMON STOCK SUBJECT TO THE PLAN

3.1. *Calculation of Number of Shares Available.* Subject to the following provisions of this Section 3, the aggregate number of shares of Common Stock that may be issued pursuant to all Awards under the Plan is 19,200,000 shares of Common Stock; provided, however, that the maximum number of shares of Common Stock issued in connection with Full Value Share Awards which may be issued under the Plan shall be limited to 9,000,000.

If any share of Common Stock that is the subject of an Award is not issued and ceases to be issuable for any reason, or is forfeited, cancelled or returned to AEP for failure to satisfy vesting requirements or upon the occurrence of other forfeiture events, such share of Common Stock will no longer be charged against the foregoing maximum share limitations and may again be made subject to Awards under the Plan pursuant to such limitations.

3.2. *Accounting for Awards.* For purposes of this Section 3, if an Award is denominated in shares of Common Stock, the number of shares covered by such Award, or to which such Award relates, shall be counted on the Date of Grant of such Award against the aggregate number of shares available for granting Awards under the Plan; provided, however, that Awards that operate in tandem with (whether granted simultaneously with or at a different time from) other Awards may be counted or not counted under procedures adopted by the Committee in order to avoid double counting.

3.3. *Source of Shares of Common Stock Deliverable Under Awards.* The shares of Common Stock to be delivered under the Plan may be authorized but unissued shares, reacquired shares, shares acquired on the open market specifically for distribution under the Plan, or any combination thereof.

3.4. *Adjustments.* If there shall occur any recapitalization, reclassification, stock dividend, stock split, reverse stock split or other distribution with respect to the shares of Common Stock, or any similar corporate transaction or event in respect of the Common Stock, then the Committee shall, in the manner and to the extent that it deems appropriate and equitable to the Participants and consistent with the terms of this Plan, cause a proportionate adjustment to be made in (a) the maximum numbers and kind of shares provided in Section 3.1 hereof, (b) the maximum numbers and kind of shares set forth in Sections 6.1, 7.1, 8.2 and 9.4 hereof, (c) the number and kind of shares of Common Stock, share units, or other rights subject to the then-outstanding Awards, (d) the price for each share or unit or other right subject to then outstanding Awards without change in the aggregate purchase price or value as to which such Awards remain exercisable or subject to restrictions, (e) the performance targets or goals appropriate to any outstanding Performance Awards (subject to such limitations as appropriate for Awards intended to qualify for exemption under Section 162(m)) or (f) any other terms of an Award that are affected by the event. Notwithstanding the foregoing, in the case of Incentive Stock Options, any such adjustments shall be made in a manner consistent with the requirements of Section 424(a) of the Code.

4. ADMINISTRATION OF THE PLAN

4.1. *Committee Members.* Except as provided in Section 4.4 hereof, the Committee will administer the Plan. The Committee may exercise such powers and authority as may be necessary or appropriate for the Committee to carry out its functions as described in the Plan. No member of the Committee will be liable for any action or determination made in good faith by the Committee with respect to the Plan or any Award under it.

4.2. *Discretionary Authority.* Subject to the express limitations of the Plan, the Committee has authority in its discretion to determine the Eligible Persons to whom, and the time or times at which, Awards may be granted, the number of shares, units or other rights subject to each Award, the exercise, base or purchase price of an Award (if any), the time or times at which an Award will become vested, exercisable or payable, the performance criteria, performance goals and other conditions of an Award, and the duration of the Award. The Committee also has discretionary authority to interpret the Plan, to make all factual determinations under the Plan, and to determine the terms and provisions of the respective Award Agreements and to make all other determinations necessary or advisable for Plan administration. The Committee has authority to prescribe, amend, and rescind rules and regulations relating to the Plan. All interpretations, determinations, and actions by the Committee will be final, conclusive, and binding upon all parties.

4.3. *Changes to Awards.* The Committee shall have the authority to effect, at any time and from time to time, with the consent of the affected Participants, (a) the cancellation of any or all outstanding Awards and the grant in substitution therefor of new Awards covering the same or different numbers of shares of Common Stock and having an exercise or base price which may be the same as or different than the exercise or base price of the cancelled Awards or (b) the amendment of the terms of any and all outstanding Awards; provided, however, that the Committee shall not have the authority to reduce the exercise or base price of an Award by amendment or cancellation and substitution of an existing Award without the approval of AEP's shareholders. The Committee may in its discretion accelerate the vesting or exercisability of an Award at any time or on the basis of any specified event.

4.4. *Delegation of Authority.* As permitted by law, the Committee may delegate its authority as identified hereunder; provided, however, that the Committee may not delegate certain of its responsibilities hereunder if such delegation may jeopardize compliance with the "outside directors" provision of Section 162(m).

4.5 *Awards to Non-Employee Directors.* The Board shall approve an Award to a Non-Employee Director under the Plan. With respect to Awards to Non-Employee Directors, all rights, powers and authorities vested in the Committee under the Plan shall instead be exercised by the Board, and all provisions of the Plan relating to the Committee shall be interpreted in a manner consistent with the foregoing by treating any such reference as a reference to the Board for such purpose.

5. ELIGIBILITY AND AWARDS

All Eligible Persons are eligible to be designated by the Committee to receive an Award under the Plan. The Committee has authority, in its sole discretion, to determine and designate from time to time those Eligible Persons who are to be granted Awards, the types of Awards to be granted and the number of shares or units subject to the Awards that are granted under the Plan. Each Award will be evidenced by an Award Agreement as described in Section 13 hereof between AEP and the Participant that shall include the terms and conditions consistent with the Plan as the Committee may determine.

6. STOCK OPTIONS

6.1. *Grant of Option.* An Option may be granted to any Eligible Person selected by the Committee; provided, however, that only Employees shall be eligible for Awards of Incentive Stock Options. Each Option shall be designated, at the discretion of the Committee, as an Incentive Stock Option (if applicable) or a Nonqualified Stock Option. The maximum number of shares of Common Stock that may be granted under Options to any one Participant during any three calendar year period shall be limited to 2,000,000 shares (subject to adjustment as provided in Section 3.4 hereof).

6.2. *Exercise Price.* The exercise price of the Option shall be determined by the Committee; provided, however, that the exercise price per share of an Option shall not be less than 100 percent of the Fair Market Value per share of the Common Stock on the Date of Grant.

6.3. *Vesting; Term of Option.* The Committee, in its sole discretion, shall prescribe in the Award Agreement the time or times at which, or the conditions upon which, an Option or portion thereof shall become vested and exercisable, and may accelerate the exercisability of any Option at any time.

6.4. *Option Exercise; Withholding.* Subject to such terms and conditions as shall be specified in an Award Agreement and to all applicable legal requirements, an Option may be exercised in whole or in part at any time during the term thereof by written notice to AEP together with payment of the aggregate exercise price therefor. Payment of the exercise price shall be made (a) in cash or by cash equivalent, (b) at the discretion of the Committee, in shares of Common Stock acceptable to the Committee, valued at the Fair Market Value of such shares on the date of exercise or such lower price as the Committee may determine, (c) at the discretion of the Committee, by a delivery of a notice that the Participant has placed a market sell order (or similar instruction) with a third party with respect to shares of Common Stock then issuable upon exercise of the Option, and that the third party has been directed to pay a sufficient portion of the net proceeds of the sale to AEP in satisfaction of the Option exercise price or (d) at the discretion of the Committee, by a combination of the methods described above or such other method as may be approved by the Committee. In addition to and at the time of payment of the exercise price, the Participant shall pay to AEP the full amount of any and all applicable income tax and employment tax amounts required to be withheld in connection with such exercise.

6.5. *Additional Rules for Incentive Stock Options.* The terms of any Incentive Stock Option granted under the Plan shall comply in all respects with the provisions of Section 422 of the Code, or any successor provision thereto, and any regulations promulgated thereunder.

7. STOCK APPRECIATION RIGHTS

7.1. *Grant of SARs.* A Stock Appreciation Right granted to a Participant is an Award in the form of a right to receive, upon surrender of the right, but without other payment, an amount based on appreciation in the Fair Market Value of the Common Stock over a base price established for the Award, exercisable at such time or times and upon conditions as may be approved by the Committee. The maximum number of shares of Common Stock that may be subject to SARs granted to any one Participant during any three calendar year period shall be limited to 2,000,000 shares (subject to adjustment as provided in Section 3.4 hereof).

7.2. *Tandem SARs.* A Stock Appreciation Right may be granted in connection with an Option, either at the time of grant or at any time thereafter during the term of the Option. A SAR granted in connection with an Option will entitle the holder, upon exercise, to surrender such Option or any portion thereof to the extent unexercised, with respect to the number of shares as to which such SAR is exercised, and to receive payment of an amount computed as described in Section 7.4 hereof. Such Option will, to the extent and when surrendered, cease to be exercisable. A SAR granted in connection with an Option hereunder will have a base price per share equal to the per share exercise price of the Option, will be exercisable at such time or times, and only to the extent, that a related Option is exercisable, and will expire no later than the related Option expires.

7.3. *Freestanding SARs.* A Stock Appreciation Right may be granted without relationship to an Option and, in such case, will be exercisable as determined by the Committee. The base price of a SAR granted without relationship to an Option shall be determined by the Committee in its sole discretion; provided, however, that the base price per share of a freestanding SAR shall not be less than 100 percent of the Fair Market Value of the Common Stock on the Date of Grant.

7.4. *Payment of SARs.* A SAR will entitle the holder, upon exercise of the SAR, to receive payment of an amount determined by multiplying: (i) the excess of the Fair Market Value of a share of Common Stock on the date of exercise of the SAR over the base price of such SAR, by (ii) the number of shares as to which such SAR will have been exercised. Payment of the amount determined under the foregoing may be made, in the discretion of the Committee, in cash, in Restricted Stock or shares of unrestricted Common Stock (both valued at their Fair Market Value on the date of exercise or such lower price as the Committee may determine), or a combination thereof; provided, however, that any shares of Common Stock used to settle or pay SARs will be counted as Full Value Share Awards.

8. RESTRICTED STOCK

8.1. *Grants of Restricted Stock.* An Award of Restricted Stock to a Participant represents shares of Common Stock that are issued subject to such restrictions on transfer and other incidents of ownership and such forfeiture conditions as the Committee may determine. The Committee may grant and designate Awards of Restricted Stock that are intended to qualify for exemption under Section 162(m), as well as Awards of Restricted Stock that are not intended to so qualify.

8.2. *Vesting Requirements.* The restrictions imposed on an Award of Restricted Stock shall lapse in accordance with the vesting requirements specified by the Committee in the Award Agreement. Such vesting requirements may be based on the continued employment of the Participant with AEP or its Subsidiaries for a specified time period or periods. Such vesting requirements may also be based on the attainment of specified business goals or measures established by the Committee in its sole discretion. In the case of any Award of Restricted Stock that is intended to qualify for exemption under Section 162(m), the vesting requirements shall be limited to the performance criteria identified in Section 9.3 below, and the terms of the Award shall otherwise comply with the Section 162(m) requirements described in Section 9.4 hereof; provided, however, that the maximum number of shares of Common Stock that may be subject to an Award of Restricted Stock granted to a Section 162(m) Participant during any one calendar year shall be separately limited to 400,000 shares (subject to adjustment as provided in Section 3.4 hereof).

8.3. *Restrictions.* Shares of Restricted Stock may not be transferred, assigned or subject to any encumbrance, pledge or charge until all applicable restrictions are removed or expire or unless otherwise allowed by the Committee. The Committee may require the Participant to enter into an escrow agreement providing that the certificates representing Restricted Stock granted pursuant to the Plan will remain in the physical custody of an escrow holder until all restrictions are removed or expire. Failure to satisfy any applicable restrictions shall result in the subject shares of Restricted Stock being forfeited and returned to AEP, unless otherwise provided by the Committee. The Committee may require that certificates representing Restricted Stock granted under the Plan bear a legend making appropriate reference to the restrictions imposed.

8.4. *Rights as Shareholder.* Subject to the foregoing provisions of this Section 8 and the applicable Award Agreement, the Participant will have all rights of a shareholder with respect to shares of Restricted Stock granted to the Participant, including the right to vote the shares and receive all dividends and other distributions paid or made with respect thereto, unless the Committee determines otherwise at the time the Restricted Stock is granted, as set forth in the Award Agreement.

8.5. *Section 83(b) Election.* The Committee may provide in an Award Agreement that the Award of Restricted Stock is conditioned upon the Participant refraining from making an election with respect to the Award under Section 83(b) of the Code. Irrespective of whether an Award is so conditioned, if a Participant makes an election pursuant to Section 83(b) of the Code with respect to an Award of Restricted Stock, the Participant shall be required to promptly provide a copy of such election to AEP as directed by the Award Agreement or the Committee.

9. PERFORMANCE AWARDS

9.1. *Grant of Performance Awards.* The Committee may grant Performance Awards under the Plan, which shall be represented by units denominated on the Date of Grant either in shares of Common Stock (Performance Shares) or in specified dollar amounts (Performance Units). The Committee may grant and designate Performance Awards that are intended to qualify for exemption under Section 162(m), as well as Performance Awards that are not intended to so qualify. At the time a Performance Award is granted, the Committee shall determine, in its sole discretion, one or more performance periods and performance goals to be achieved during the applicable performance periods, as well as such other restrictions and conditions as the Committee deems appropriate. In the case of Performance Units, the Committee shall also determine a target unit value or a range of unit values for each Award. The performance goals applicable to a Performance Award grant may be subject to such later revisions as the Committee shall deem appropriate to reflect significant unforeseen events such as changes in law, accounting practices or unusual or nonrecurring items or occurrences. Any such adjustments shall be subject to such limitations as the Committee deems appropriate in the case of a Performance Award granted to a Section 162(m) Participant that is intended to qualify for exemption under Section 162(m).

9.2. *Payment of Performance Awards.* At the end of the performance period, the Committee shall determine the extent to which performance goals have been attained or a degree of achievement between minimum and maximum levels in order to establish the level of payment to be made, if any. The Committee shall determine if payment is to be made in cash, Restricted Stock, shares of unrestricted Common Stock, Options or Phantom Stock, or a combination thereof. For any cash conversion to or from Performance Shares or Units, Phantom Stock units or shares of Common Stock, payment shall be calculated on the basis of the average of the Fair Market Value of the Common Stock for the last 20 trading days prior to the date such award becomes payable.

9.3. *Performance Criteria.* The performance criteria upon which the payment or vesting of a Performance Award intended to qualify for exemption under Section 162(m) may be based shall be limited to the following business measures, which may be applied with respect to AEP, any Subsidiary or any business unit, and which may be measured on an absolute or relative-to-peer-group basis: earnings measures (including, for example, primary earnings per share, fully diluted earnings per share, net income, pre-tax income, operating income, earnings before interest, taxes, depreciation and amortization or any combination thereof, and net operating profits after taxes); expense control (including, for example, operations & maintenance expense, total expenditures, expense ratios, and expense reduction); customer measures (including, for example, customer satisfaction, service cost, service levels, responsiveness, bad debt collections or losses, and reliability – such as outage frequency, outage duration, and frequency of momentary outages); safety measures (including, for example, recordable case rate, severity rate, and vehicle accident rate); diversity measures (including, for example, minority placement rate and utilization); environmental measures (including, for example, emissions, project completion milestones, regulatory/legislative/cost recovery goals, and notices of violation), revenue measures (including, for example, revenue and direct margin); stakeholder return measures (including, for example, total shareholder return, economic value added, cumulative shareholder value added, return on equity, return on capital, return on assets, dividend payout ratio and cash flow(s) – such as operating cash flows, free cash flow, discounted cash flow return on investment and cash flow in excess of cost of capital or any combination thereof); valuation measures (including, for example, stock price increase, price to book value ratio, and price to earnings ratio); capital and risk measures (including, for example, debt to equity ratio, dividend payout as percentage of net income and diversification of business opportunities); employee satisfaction; project measures (including, for example, completion of key milestones); production measures (including, for example, generating capacity factor, performance against the INPO index, generating equivalent availability, heat rates and production cost); and such other individual performance objective that is measured solely in terms of quantitative targets related to the Company, any Subsidiary or the Company's or Subsidiary's business. In any event, the Committee may, at its discretion and at any time prior to payment, reduce the number of Performance Awards earned by any Participant for a performance period. In the case of Performance Awards that are not intended to qualify for exemption under Section 162(m), the Committee shall designate performance criteria from among the foregoing or such other business criteria as it shall determine in its sole discretion.

9.4. *Section 162(m) Requirements.* In the case of a Performance Award granted to a Section 162(m) Participant that is intended to comply with the requirements for exemption under Section 162(m), the Committee shall make all determinations necessary to establish a Performance Award within 90 days of the beginning of the performance period (or such other time period required under Section 162(m)), including, without limitation, the designation of the Section 162(m) Participants to whom Performance Awards are made, the performance criteria or criterion applicable to the Award and the performance goals that relate to such criteria, and the dollar amounts or number of shares of Common Stock, Restricted Stock or Phantom Stock units payable upon achieving the applicable performance goals. As and to the extent required by Section 162(m), the terms of a Performance Award granted to a Section 162(m) Participant must include objective formula(s) or standard(s) for computing the amount of compensation payable to the Section 162(m) Participant, and must preclude discretion to increase the amount of compensation payable that would otherwise be due under the terms of the Award. The maximum amount of compensation that may be payable to a Section 162(m) Participant during any one calendar year under a Performance Unit Award shall be $15,000,000. The maximum number of Performance Share units that may be earned by a Section 162(m) Participant during any one calendar year shall be 400,000 (subject to adjustment as provided in Section 3.4 hereof).

10. PHANTOM STOCK

10.1. *Grant of Phantom Stock.* Phantom Stock is an Award to a Participant of a number of hypothetical share units with respect to shares of Common Stock. Phantom Stock shall be subject to such restrictions and conditions as the Committee shall determine. Sections 8.1 and 8.2 shall apply to Awards of Phantom Stock units in similar manner as they apply to shares of Restricted Stock, as interpreted by the Committee, with the limitation in Section 8.2 on the number of shares of Restricted Stock that may be granted applicable separately to Phantom Stock units. An Award of Phantom Stock may be granted, at the discretion of the Committee, together with an Award of Dividend Equivalent rights for the same number of shares covered thereby.

10.2. *Payment of Phantom Stock.* Upon the vesting date applicable to Phantom Stock granted to a Participant, an amount equal to one share of Common Stock upon such date shall be paid with respect to such Phantom Stock unit granted to the Participant. Payment may be made, at the discretion of the Committee, in cash, Restricted Stock, shares of unrestricted Common Stock, Options, or a combination thereof. Cash payments of Phantom Stock units shall be calculated on the basis of the average of the Fair Market Value of the Common Stock for the last 20 trading days prior to the date such award becomes payable.

11. DIVIDEND EQUIVALENTS

A Dividend Equivalent granted to a Participant is an Award in the form of a right to receive cash, shares of Common Stock, or other property equal in value to dividends paid with respect to a specific number of shares of Common Stock. Dividend Equivalents may be awarded on a free-standing basis or in connection with another Award, and may be paid currently or on a deferred basis. The Committee may provide at the Date of Grant or thereafter that the Dividend Equivalent shall be paid or distributed when accrued or shall be deemed to have been reinvested in additional shares of Common Stock or such other investment vehicles as the Committee may specify; provided, however, that Dividend Equivalents (other than free-standing Dividend Equivalents) shall be subject to all conditions and restrictions of the underlying Awards to which they relate.

12. CHANGE IN CONTROL

12.1. *Effect of Change in Control.* The Committee may, in an Award Agreement, provide for the effect of a Change in Control on an Award. Such provisions may include any one or more of the following: (a) the acceleration or extension of time periods for purposes of exercising, vesting in, or realizing gain from any Award, (b) the waiver or modification of performance or other conditions related to the payment or other rights under an Award; (c) provision for the cash settlement of an Award for an equivalent cash value, as determined by the Committee, or (d) such other modification or adjustment to an Award as the Committee deems appropriate to maintain and protect the rights and interests of Participants upon or following a Change in Control.

12.2. *Definition of Change in Control.* For purposes hereof, a "Change in Control" shall be deemed to have occurred if:

(a) any "person" or "group" (as such terms are used in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934 ("Exchange Act")), other than any company owned, directly or indirectly, by the shareholders of AEP in substantially the same proportions as their ownership of shares of Common Stock or a trustee or other fiduciary holding securities under an employee benefit plan of AEP, becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of more than 25 percent of the then outstanding voting stock of AEP;

(b) during any period of two consecutive years, individuals who at the beginning of such period constitute the Board, together with any new directors (other than a director nominated by a person (i) who has entered into an agreement with AEP to effect a transaction described in Section 12.2(a), (c) or (d) hereof or (ii) who publicly announces an intention to take or consider taking actions (including, but not limited to, an actual or threatened proxy contest) which if consummated would constitute a Change in Control) whose election or nomination for election was approved by a vote of at least two-thirds of the directors then still in office who were either directors at the beginning of the period or whose election or nomination for election was previously so approved, cease for any reason (except for death, disability or voluntary retirement) to constitute at least a majority of the Board;

(c) AEP consummates a merger or consolidation with any other entity, other than a merger or consolidation which would result in the voting securities of AEP outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity) at least 50 percent of the total voting power represented by the voting securities of AEP or such surviving entity outstanding immediately after such merger or consolidation; or

(d) the shareholders of AEP approve a plan of complete liquidation of AEP, or an agreement for the sale or disposition by AEP (in one transaction or a series of transactions) of all or substantially all of AEP's assets.

Notwithstanding the foregoing, a Change in Control shall not be deemed to occur as a result of any event in (a) or (c) above, if directors who were members of the Board prior to such event continue to constitute a majority of the Board after such event.

13. AWARD AGREEMENTS

13.1. *Form of Agreement.* Each Award under this Plan shall be evidenced by an Award Agreement in a form approved by the Committee setting forth the number of shares of Common Stock, units or other rights (as applicable) subject to the Award, the exercise, base or purchase price (if any) of the Award, the time or times at which an Award will become vested, exercisable or payable, the duration of the Award and, in the case of Performance Awards, the applicable performance criteria and goals. The Award Agreement shall also set forth other material terms and conditions applicable to the Award as determined by the Committee consistent with the limitations of this Plan. Award Agreements evidencing Awards intended to qualify for exemption under Section 162(m) may be designated as such and shall contain such terms and conditions as may be necessary to meet the applicable requirements of Section 162(m). Award Agreements evidencing Incentive Stock Options shall contain such terms and conditions as may be necessary to meet the applicable provisions of Section 422 of the Code.

13.2. *Contract Rights; Amendment.* Any obligation of AEP to any Participant with respect to an Award shall be based solely upon contractual obligations created by an Award Agreement. No Award shall be enforceable until the Award Agreement has been signed on behalf of AEP by its authorized representative and signed by the Participant and returned to AEP as directed by the Award Agreement or the Committee. By executing the Award Agreement, a Participant shall be deemed to have accepted and consented to the terms of this Plan and any action taken in good faith under this Plan by and within the discretion of the Committee, the Board or their delegates. Award Agreements covering outstanding Awards may be amended or modified by the Committee in any manner that may be permitted for the grant of Awards under the Plan, subject to the consent of the Participant to the extent provided in the Award Agreement. However, the offer of an Award Agreement to a particular Eligible Person shall not infer any obligation to offer any other Award Agreements at that or any other time.

14. GENERAL PROVISIONS

14.1. *Limits on Transfer of Awards; Beneficiaries.* Except to the extent specifically provided by the terms of an Award Agreement, Awards shall be nontransferable. During the lifetime of a Participant, Awards shall be exercised only by such Participant or by his guardian or legal representative. Notwithstanding the foregoing, the Committee may provide in the terms of an Award Agreement that the Participant shall have the right to designate a beneficiary or beneficiaries who shall be entitled to any rights, payments or other benefits specified under an Award Agreement following the Participant's death.

14.2. *Deferrals of Payment.* In an Award Agreement or under a separate policy or program adopted by the Committee, a Participant may be permitted or required to defer the receipt of payment of cash or delivery of shares of Common Stock that would otherwise be due to the Participant by virtue of the exercise of a right or the satisfaction of vesting or other conditions with respect to an Award. Any such policy or program shall establish the rules and procedures relating to such deferral, including, without limitation, the period of time in advance of payment when an election to defer may be made, the time period of the deferral and the events that would result in payment of the deferred amount, the interest or other earnings attributable to the deferral and the method of funding, if any, attributable to the deferred amount.

14.3. *Rights as Shareholder.* A Participant shall have no rights as a holder of Common Stock with respect to any unissued securities covered by an Award until the date the Participant becomes the holder of record of these securities. Except as provided in Section 3.4 hereof, no adjustment or other provision shall be made for dividends or other shareholder rights, except to the extent that the Award Agreement provides for Dividend Equivalents, dividend payments or similar economic benefits.

14.4. *Employment or Service.* Nothing in the Plan, in the grant of any Award or in any Award Agreement shall confer upon any Eligible Person the right to continue in the capacity in which he is employed by or otherwise serves AEP or any Subsidiary.

14.5. *Securities Laws.* No shares of Common Stock will be issued or transferred pursuant to an Award unless and until all then applicable requirements imposed by federal and state securities and other laws, rules and regulations and by any regulatory agencies having jurisdiction, and by any stock exchanges upon which the Common Stock may be listed, have been fully met. As a condition precedent to the issuance of shares pursuant to the grant or exercise of an Award, AEP may require the Participant to take any reasonable action to meet such requirements. The Committee may impose such conditions on any shares of Common Stock issuable under the Plan as it may deem advisable, including, without limitation, restrictions under the Securities Act of 1933, as amended, under the requirements of any stock exchange upon which such shares of the same class are then listed, and under any blue sky or other securities laws applicable to such shares.

14.6. *Taxes and Withholding.* The Participant shall be responsible for payment of any taxes or similar charges required by law with respect to each Award or an amount paid in satisfaction of an Award. AEP and its Subsidiaries, as applicable, shall comply with the terms of a deduction election made by a Participant with any payment made under the terms of an Award Agreement, but only if and to the extent applicable thereto. AEP and its Subsidiaries, as applicable, may withhold and disburse such amount or amounts it determines to be required for purposes of complying with obligations for tax withholding or such other obligations under applicable federal, state and local law. The Committee in its sole discretion may direct AEP to satisfy all or part of applicable tax withholding obligations incident to a Participant's exercise of a Stock Option or to the vesting of Stock Appreciation Rights, Restricted Stock, Performance Shares, Performance Units or Phantom Stock by AEP's withholding of a portion of the Common Stock that otherwise would have been issued to such Participant.

14.7. *Unfunded Plan.* The adoption of this Plan and any setting aside of cash amounts or shares of Common Stock by AEP with which to discharge its obligations hereunder shall not be deemed to create a trust or other funded arrangement. The benefits provided under this Plan shall be a general, unsecured obligation of AEP payable solely from the general assets of AEP, and neither a Participant nor the Participant's permitted transferees or estate shall have any interest in any assets of AEP by virtue of this Plan, except as a general unsecured creditor of AEP. Notwithstanding the foregoing, AEP shall have the right to implement or set aside funds in a grantor trust subject to the claims of AEP's creditors to discharge its obligations under the Plan.

14.8. *Other Compensation and Benefit Plans.* The adoption of the Plan shall not affect any other stock incentive or other compensation plans in effect for AEP or any Subsidiary, nor shall the Plan preclude AEP from establishing any other forms of stock incentive or other compensation for employees of AEP or any Subsidiary. The amount of any compensation deemed to be received by the Participant pursuant to an Award shall not constitute compensation with respect to which any other employee benefits of such Participant are determined, including, without limitation, benefits under any bonus, pension, profit sharing, life insurance or salary continuation plan, except as otherwise specifically provided by the terms of such plan.

14.9. *Plan Binding on Successors.* The Plan shall be binding upon AEP, its successors and assigns, and the Participant, his executor, administrator and permitted transferees and beneficiaries.

14.10. *Construction and Interpretation.* Whenever used herein, nouns in the singular shall include the plural, and the masculine pronoun shall include the feminine gender. Headings of Sections hereof are inserted for convenience and reference and constitute no part of the Plan.

14.11. *Severability.* If any provision of the Plan or any Award Agreement shall be determined to be illegal or unenforceable by any court of law in any jurisdiction, the remaining provisions hereof and thereof shall be severable and enforceable in accordance with their terms, and all provisions shall remain enforceable in any other jurisdiction.

14.12. *Governing Law.* The laws of the State of Ohio shall govern the validity and construction of this Plan and of the Award Agreements, without giving effect to principles relating to conflict of laws, except to the extent that such laws may be preempted by Federal law.

14.13. *Compliance with Rule 16b-3.* It is the intent of AEP that this Plan comply in all respects with Rule 16b-3 in connection with any Award granted to a person who is subject to Section 16 of the Exchange Act. Accordingly, if any provision of this Plan or any Award Agreement does not comply with the requirements of Rule 16b-3 as then applicable to any such person, such provision shall be construed or deemed amended to the extent necessary to conform to such requirements with respect to such person.

15. EFFECTIVE DATE, TERMINATION AND AMENDMENT

15.1. *Effective Date; Shareholder Approval.* Subject to approval by the Securities and Exchange Commission, the Effective Date of the Plan shall be the date following adoption of the Plan by the Board on which the Plan is approved by the shareholders of AEP. Grants of Awards under the Plan may be made prior to the Effective Date (but after adoption of the Plan by the Board), subject to approval of the Plan by the Securities and Exchange Commission and the shareholders. At the sole discretion of the Board, in order to comply with the requirements of Section 162(m) for certain types of Awards under the Plan, the performance criteria set forth in Section 9.3 shall be reapproved by the shareholders no later than the first shareholder meeting that occurs in the fifth calendar year following the calendar year of the initial shareholder approval of such performance criteria.

15.2. *Termination.* The Plan shall remain in effect until terminated by action of the Board; provided, however, that no Award may be granted hereunder after April 26, 2015.

Notwithstanding the foregoing, no termination of the Plan shall in any manner affect any Award theretofore granted without the consent of the Participant or the permitted transferee of the Award.

15.3. *Amendment.* The Board may at any time and from time to time and in any respect, amend or modify the Plan; provided, however, that no amendment or modification of the Plan shall be effective without the consent of AEP's shareholders that would (a) increase the number of shares of Common Stock reserved for issuance or (b) allow the grant of Options at an exercise price below Fair Market Value, or allow the repricing of Options without AEP shareholder approval. In addition, the Board may seek the approval of any amendment or modification by AEP's shareholders to the extent it deems necessary or advisable in its sole discretion for purposes of compliance with Section 162(m) or Section 422 of the Code, the listing requirements of the New York Stock Exchange or for any other purpose. No amendment or modification of the Plan shall in any manner affect any Award theretofore granted without the consent of the Participant or the permitted transferee of the Award.

AEP
AMERICAN ELECTRIC POWER®

1 Riverside Plaza
Columbus, OH 43215–2378

Appendix A to the
Proxy Statement

American Electric Power

2004 Annual Report

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

AEP AMERICAN ELECTRIC POWER

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

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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, 2004	$ 35.53	$ 31.25	$ 34.34	$ 0.35
September 30, 2004	33.21	30.27	31.96	0.35
June 30, 2004	33.58	28.50	32.00	0.35
March 31, 2004	35.10	30.29	32.92	0.35
December 31, 2003	30.59	26.69	30.51	0.35
September 30, 2003	30.00	26.58	30.00	0.35
June 30, 2003	31.51	22.56	29.83	0.35
March 31, 2003	30.63	19.01	22.85	0.60

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2004, AEP had approximately 130,000 registered shareholders.

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 electric utility subsidiary of AEP.
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 domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEPR.
AEPR	AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	The Clean Air Act.
CenterPoint	CenterPoint Energy Houston Electric, LLC, Reliant Energy Retail Services, LLC, and Texas Genco LP, all of which are not affiliated with AEP.
Cook Plant	The Donald C. Cook Nuclear Plant, a two-unit, 2,110 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.).
DETM	Duke Energy Trading and Marketing L.L.C., a nonaffiliated risk management counterparty.
DOE	United States Department of Energy.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 02-3	Emerging Issues Task Force Issue No. 02-3: Issues Involved in Accounting for Derivative Contracts Held For Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.
ERCOT	The Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities."
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipeline Company.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPP	Independent Power Producers.
ISO	Independent System Operator.
JMG	JMG Funding LP, a variable interest entity consolidated by OPCo.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.

KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas Co., a former AEP subsidiary.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
NSR	New source review.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
Parent	American Electric Power Company, Inc.
PJM	PJM Interconnection, LLC; a regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTB	Price-to-Beat.
PUCT	The Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act of 1935, as amended.
PURPA	The Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges, and nonderivative contracts held for trading purposes.
RTO	Regional Transmission Organization.
S&P	Standard & Poor's.
SEC	Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 109	Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes.
SFAS 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.
SFAS 143	Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.
SNF	Spent Nuclear Fuel.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by TCC.
STPNOC	STP Nuclear Operating Company, a nonprofit Texas corporation which operates STP on behalf of its joint owners including TCC.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Tenor	Maturity of a contract.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing to be made under the Texas Restructuring Legislation to review and finalize the amount of stranded costs, if applicable, and other true-up items and the recovery of such amounts.
TVA	Tennessee Valley Authority.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

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. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of and transportation for fuels and the creditworthiness of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- The ability to recover regulatory assets and stranded costs in connection with deregulation.
- The ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
- Oversight and/or investigation of the energy sector or its participants.
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- Our ability to constrain its operation and maintenance costs.
- Our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary trends.
- 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 and number of participants in the energy trading market.
- Changes in the financial markets, particularly those affecting the availability of capital and our ability to refinance existing debt at attractive rates.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, and other energy-related commodities.
- Changes in utility regulation, including membership and integration into regional transmission structures.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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

	2004	2003	2002	2001	2000
OPERATIONS STATEMENTS DATA			(in millions)		
Total Revenues	$ 14,057	$ 14,667	$ 13,427	$ 12,840	$ 10,854
Operating Income	1,991	1,754	1,923	2,310	1,869
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect of Accounting Changes	$ 1,127	$ 522	$ 485	$ 960	$ 177
Discontinued Operations Income (Loss), Net of Tax	83	(605)	(654)	41	134
Extraordinary Losses, Net of Tax	(121)	-	-	(48)	(44)
Cumulative Effect of Accounting Changes Gain (Loss), Net of Tax	-	193	(350)	18	-
Net Income (Loss)	$ 1,089	$ 110	$ (519)	$ 971	$ 267
BALANCE SHEET DATA			(in millions)		
Property, Plant and Equipment	$ 37,286	$ 36,021	$ 34,127	$ 32,993	$ 31,472
Accumulated Depreciation and Amortization	14,485	14,004	13,539	12,655	12,398
Net Property, Plant and Equipment	$ 22,801	$ 22,017	$ 20,588	$ 20,338	$ 19,074
Total Assets	$ 34,663	$ 36,781	$ 35,945	$ 40,432	$ 47,703
Common Shareholders' Equity	$ 8,515	$ 7,874	$ 7,064	$ 8,229	$ 8,054
Cumulative Preferred Stocks of Subsidiaries (a) (d)	$ 127	$ 137	$ 145	$ 156	$ 161
Trust Preferred Securities (b)	$ -	$ -	$ 321	$ 321	$ 334
Long-term Debt (a) (b)	$ 12,287	$ 14,101	$ 10,190	$ 9,409	$ 8,980
Obligations Under Capital Leases (a)	$ 243	$ 182	$ 228	$ 451	$ 614
COMMON STOCK DATA					
Earnings (Loss) per Common Share:					
Income Before Discontinued Operations, Extraordinary Losses and Cumulative Effect of Accounting Changes	$ 2.85	$ 1.35	$ 1.46	$ 2.98	$ 0.55
Discontinued Operations, Net of Tax	0.21	(1.57)	(1.97)	0.13	0.42
Extraordinary Losses, Net of Tax	(0.31)	-	-	(0.16)	(0.14)
Cumulative Effect of Accounting Changes, Net of Tax	-	0.51	(1.06)	0.06	-
Earnings (Loss) Per Share	$ 2.75	$ 0.29	$ (1.57)	$ 3.01	$ 0.83
Average Number of Shares Outstanding (in millions)	396	385	332	322	322
Market Price Range:					
High	$ 35.53	$ 31.51	$ 48.80	$ 51.20	$ 48.94
Low	$ 28.50	$ 19.01	$ 15.10	$ 39.25	$ 25.94
Year-end Market Price	$ 34.34	$ 30.51	$ 27.33	$ 43.53	$ 46.50
Cash Dividends Paid per Common Share	$ 1.40	$ 1.65	$ 2.40	$ 2.40	$ 2.40
Dividend Payout Ratio (c)	50.9%	569.0%	(152.9)%	79.7%	289.2%
Book Value per Share	$ 21.51	$ 19.93	$ 20.85	$ 25.54	$ 25.01

(a) Including portion due within one year.
(b) See "Trust Preferred Securities" section of Note 17.
(c) Based on AEP historical dividend rate.
(d) Includes Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption which are classified in 2003 as Noncurrent Liabilities and in 2004 as Current Liabilities as the shares were redeemed in January 2005.

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

We have an extensive portfolio of assets including:

- 36,000 megawatts of generating capacity as of December 31, 2004, the largest complement of generation in the U.S., the majority of which has a significant cost advantage in many of our market areas. In 2004, we sold utility generating capacity of 3,800 megawatts located in Texas and approximately 280 megawatts of independent power generation located in Colorado and Florida.
- Approximately 39,000 miles of transmission lines, including the backbone of the electric interconnected grid in the Eastern U.S.
- 177,000 miles of distribution lines that deliver electricity to customers.
- Substantial coal transportation assets (7,065 railcars, 2,230 barges, 53 towboats and one active coal handling terminal with 20 million tons of annual capacity).
- 4,400 miles of gas pipelines in Texas with 118 billion cubic feet of gas storage facilities, which we sold on January 26, 2005.

BUSINESS STRATEGY

Our strategy is to focus on domestic electric utility operations. Our objective is to be an economical, reliable and safe provider of electric energy to the markets that we serve. We will achieve economic advantage by designing, building, improving and operating low cost, environmentally-compliant, efficient sources of power and maximizing the volumes of power delivered from these facilities. We will maintain and enhance our position as a safe and reliable provider of electric energy by making significant investments in environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers while providing a fair return for our shareholders through a stable stream of cash flows, enabling us to pay dependable, competitive dividends. We will operate our competitive generating assets to maximize our productivity and profitability after meeting our native load requirements.

In summary our business strategy calls for us to:

Operations

- Invest in technology that improves the environment of the communities in which we operate.
- Maximize the value of our transmission assets through membership in PJM, ERCOT, and SPP.
- Continue maintaining and improving the quality of distribution service.
- Optimize generation assets by increasing availability and consequently increasing sales.

Regulation

- Focus on the regulatory process to fully recover our costs and earn a fair return while providing fair and reasonable rates to our customers while fulfilling our commitment to invest in environmental projects at our generating plants.
- Complete the sale of our generation assets in Texas and recover the associated stranded costs in compliance with the law.

Financial

- Operate only those unregulated investments that are consistent with our energy expertise and risk tolerance and that provide reasonable prospects for a fair return and moderate growth.
- Continue to improve credit quality and maintain acceptable levels of liquidity.
- Achieve moderate but steady growth.

EXECUTIVE OVERVIEW

Utility Operations

Our Utility Operations, the core of our business, had a year of continued improvement despite some unfavorable operating conditions. Our results for the year reflect the increased demand from our industrial customers and sales growth in the residential and commercial classes. These are solid indicators that the economic recovery is reaching all sectors. We also realized a positive earnings impact due to a favorable court decision in Texas, which allows us to recover carrying costs for stranded costs in Texas. However, these favorable results were not sufficient to offset the absence of the wholesale capacity auction true-up revenues in 2004 and higher planned plant maintenance and distribution system reliability improvement work. Additionally, unfavorable weather due to a mild summer in 2004 lowered our revenues below expected norms and a significant late-December ice storm in parts of our eastern territory increased our storm damage repair operations and maintenance expenses.

In May 2004, we announced the reorganization of our distribution and customer service operations into seven regional utility divisions, placing operational authority into the hands of division presidents and their support staffs. With this new structure, we have created stronger utilities by moving the decision-making closer to the customer and other external stakeholders.

On October 1, 2004, we integrated our east region transmission and generation operations, commercial processes and data systems into those of PJM. While we continue to own our transmission assets, use our low-cost generation fleet to serve the needs of our native-load customers, and sell available generation to other parties, we are performing those functions through PJM.

During the fourth quarter of 2004, our PJM-related operating results came in as expected, in spite of having to overcome the initial learning curve of operating in this new environment. We are confident in our ability to participate successfully in the PJM market.

During 2004, we further stabilized our financial strength by:

- Completing significant asset divestitures resulting in proceeds of approximately $1.4 billion.
- Using the cash flows from our asset divestitures to reduce outstanding debt, resulting in an improved debt to capital ratio of 59.1% at December 31, 2004.
- Stabilizing our credit ratings as indicated by Moody's change in outlook from 'stable' to 'positive' in August 2004.

While we were extremely successful during 2004 in reducing our outstanding debt and the related debt to total capital ratio from 64.6% to 59.1%, we have significant capital expenditures projected for the near-term. Through a combination of cash generated from operations and proceeds from our asset dispositions we expect to maintain the strength of our balance sheet and fund our capital expenditure program. After the completion of our remaining planned divestitures and after the results of our Texas true-up proceedings are finalized, we hope to recommend to the board gradual, sustainable increases to our current 35 cent per share quarterly common stock dividend.

Regulatory Matters

Ohio Rate Stabilization Plan

CSPCo and OPCo filed their rate stabilization plans on February 9, 2004 at the request of the Public Utility Commission of Ohio (PUCO) and the plans were approved, subject to rehearing, on January 26, 2005, with certain modifications. The plans are intended to provide rate stability, facilitate a competitive retail market, and provide for recovery of future environmental expenditures.

The approved plans include fixed annual percentage increases in the generation component of all customers' bills of 3% for CSPCo and 7% for OPCo in 2006, 2007 and 2008, along with the opportunity for additional generation-related increases upon PUCO review and approval. Additional generation-related increases averaging up to 4% per year for each company above the fixed annual percentage increases under the plans are possible. Distribution rates will remain fixed at the December 31, 2005 level through 2008 but could be adjusted for specified reasons with PUCO approval. Transmission rates will be adjusted based on FERC-approved OATT tariffs. We believe that these plans will favorably affect customers, shareholders and other stakeholders.

Texas Stranded Cost and Related Carrying Cost Recovery

The stranded cost recovery process in Texas continues to be very intense and time-consuming. The ultimate recovery of these assets is somewhat clearer given the recent CenterPoint decision; however, we anticipate a contentious stranded cost True-up Proceeding for TCC. The principal component of the process is the determination of TCC's net stranded generation costs regulatory asset. Other net true-up regulatory assets will also need to be recovered through customer transition charges. Although we believe that these assets are recoverable under the Texas restructuring legislation, we anticipate that other parties will contend that material amounts of stranded costs should not be recovered. TCC will seek to recover in its True-up Proceeding an amount in excess of the $1.6 billion recorded net true-up regulatory asset through December 31, 2004.

When the True-up Proceeding is completed, TCC intends to file to recover PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying charges, through a nonbypassable competition transition charge in the regulated T&D rates, and through an additional transition charge for amounts that can be recovered through securitization. We cannot predict whether our full net stranded cost and other true-up regulatory assets will be approved for recovery.

TCC Rate Case

TCC has a base rate filing for its Texas wires business pending before the PUCT in which it is requesting an adjusted $41 million rate increase. A reduction in existing rates of between $48 million and $75 million is possible depending on the final treatment of affiliated transactions. Based on preliminary decisions of the PUCT, it appears that the best result we can expect is a $6 million rate increase. The PUCT order, when issued, will affect revenues prospectively.

PSO Rate Review

In February 2003, the Corporation Commission of the State of Oklahoma (OCC) filed an application requiring PSO to file all documents necessary for a general rate review. Intervenors and OCC Staff filed testimony recommending a decrease in annual existing rates of between $15 million and $36 million. PSO's current testimony supports a revenue deficiency of $28 million. As a consequence of this case, PSO also asserts that approximately $9 million of additional costs should be recovered through the fuel adjustment clause. Hearings are scheduled to begin in March 2005, and a final decision is not expected any earlier than the second quarter of 2005. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

Environmental Stewardship

In August 2004, a subcommittee of the Policy Committee of our Board of Directors prepared a report in response to a shareholder proposal entitled, "An Assessment of AEP's Actions to Mitigate the Economic Impacts of Emissions Policies." This report assessed the actions that we are taking to mitigate the economic impact of increasing regulatory requirements, competitive pressures, and public expectations to significantly reduce carbon dioxide and other emissions. The comprehensive report made the following recommendations for managing the current challenge we face:

- Design of control regimes – engage in persuasive, proactive advocacy of positive policy positions that ensure the rules governing such programs will operate in a transparent, fair and cost-effective manner.
- Technology leadership – preserve our ability to utilize coal economically while meeting increasingly stringent emission control requirements.
- Excellence in plant operations – consistently operate emission-controlled plants at high capacity factors.
- Sophisticated decision-making tools – engage in complex decision-making processes to identify the mix of options that will minimize the cost to the consumer while at the same time factoring in the uncertainty inherent in the regulatory process.
- Transparency – make actions transparent and understandable to shareholders, customers and stakeholders.
- Partnerships – continue to seek out partners as we work out options to control greenhouse gas and other emissions.

The report concluded that the actions we have taken are a solid foundation for our future efforts to balance environmental policy and business opportunities. This conclusion is further evidenced by an award received in January 2005 from the Edison Electric Institute related to our advocacy efforts to support mercury cap-and-trade and the accompanying sulfur dioxide and nitrogen oxide regulations.

Asset Sales

While we made significant progress on our divestiture plans in 2004, we have four remaining assets to be sold. We sold the Pushan Power Plant, LIG Pipeline Company, Jefferson Island Storage & Hub, AEP Coal, four Independent Power Producers (IPPs), our U.K. operations, TCC and TNC generation assets, Numanco LLC and our 50% ownership in South Coast Power Limited during 2004, which generated proceeds of approximately $1.4 billion. In addition, on January 27, 2005, we announced the sale of 98% of our interest in Houston Pipeline Company, including gas and working capital, for $1 billion. This sale essentially completes our divestiture of natural gas assets in the U.S.

TCC Generation Assets

The largest remaining asset sale yet to close is the South Texas Project (STP) for approximately $333 million, followed by TCC's ownership interest in the Oklaunion asset for approximately $43 million. Under the existing PUCT rule, both of these assets must be sold before we can proceed with our Texas True-Up Proceeding. We have entered into agreements to sell TCC's interest in both facilities and we expect the sales to be completed in the first half of 2005, although the sale of Oklaunion could be delayed by litigation. TCC is considering seeking a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to closing of the sales of all generation assets.

Bajio

Our Bajio investment represents a 50% interest in a 600 MW natural gas-fired facility in Mexico. We have retained an advisor and the sale process is underway. Based on indicative bids received in the fourth quarter of 2004, we recorded an impairment of approximately $13 million. We expect a sale to close in 2006.

Pacific Hydro

Our Pacific Hydro investment represents a 20% interest in an Australian company that develops and operates renewable energy facilities including hydro, wind and geothermal facilities in the Pacific Rim. We have retained an advisor and have identified a preferred bidder. We expect the sale to close in the first half of 2005.

Fuel Costs

Market prices for coal, natural gas and oil have increased dramatically during 2004. These increasing fuel costs are the result of increasing worldwide demand, supply uncertainty, and transportation constraints, as well as other market factors. We manage price and performance risk, particularly for coal, through a portfolio of contracts of varying durations and other fuel procurement and management activities. We have fuel recovery mechanisms for about 50% of our fuel costs in our various jurisdictions. Additionally, about 20% of our fuel is used for off-system sales where power prices we receive for our power sales should recover our cost of fuel. Accordingly, approximately 70% of fuel cost increases are recovered. The remaining 30% of our fuel costs relate to Ohio and West Virginia customers, where we do not have a fuel cost recovery mechanism. We currently have 100% and 85% of our projected coal needs for 2005 and 2006, respectively, under contract.

Capital Expenditures

Environmental

We previously announced plans to invest approximately $3.7 billion in capital from 2004 to 2010, and a total of $5 billion through 2020, to install pollution control equipment that preserves the low cost generation from our coal-fired power plants. Of the $3.7 billion environmental investment plan, $1.9 billion relates to compliance with current laws and the remaining $1.8 billion is intended to cover additional environmental controls that may be required in the future based on current legislative proposals to further reduce emissions and mercury. Forty-nine percent of our $3.7 billion capital plan relates to Ohio generation facilities, followed by Virginia and West Virginia for a combined 34 percent, and Kentucky with 12 percent. Our overall relationships with regulators are important to our growth strategy and our goal of producing low-cost electricity with minimal impact on the environment. We intend to support this investment program through the use of free cash flow and rate increases and therefore, at this time, do not anticipate material incremental leveraging. It is important that we manage the regulatory process to ensure that we receive fair recovery of our costs, including capital costs, as we fulfill our commitment to invest in environmental projects at our generating plants.

Advanced Technology
In conjunction with our environmental analysis issued in August 2004, we announced plans to construct synthetic-gas-fired power plant(s) with at least a combined 1,000 MW of capacity in the next five to six years utilizing new integrated gasification combined cycle (IGCC) technology. We estimate that the new plant(s) will cost approximately $1.7 billion, based on Electric Power Research Institute cost studies. Our detailed studies are underway to fully define the project. We have not determined a location for the plant, but it will likely be in one of our eastern states, because of ready access to coal and the need for capacity in the selected jurisdiction. We are currently performing site analysis and evaluation and at the same time working with state regulators and legislators to establish a framework for expedient recovery of this significant investment in new clean coal technology before final site selection. Our significant planned environmental investments and our commitment to IGCC technology reinforces our belief that coal will be a lower-emission domestic fuel source of the future and further signals our commitment to investing in clean, environmentally safe technology.

See further discussion of these matters in detail in the Notes to Financial Statements and later in Management's Discussion and Analysis under the heading of Significant Factors. We expect to diligently resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our investors.

OUTLOOK FOR 2005

We remain focused on the fundamental earning power of our utilities, and we are committed to maintaining the strength of our balance sheet. Our strategy for achieving these goals is well planned. We expect to:

- Continue to identify opportunities to increase the efficiency of our operations and capital expenditure program.
- Seek rate changes that are fair and reasonable and that allow us to make the necessary operational, reliability and environmental improvements to our system.
- Efficiently manage generating facilities to benefit our customers and to maximize off-system sales.
- Successfully operate unregulated investments such as our wind farms and our barge and river transport groups, which complement our core utility operations.
- Pursue new environmentally friendly, state of the art coal-fired power plants.

There are, nevertheless, certain risks and challenges including:

- Rate activity such as the TCC wires rate case and the PSO rate case.
- Completion of our asset sales, including the remaining TCC generation assets.
- TCC stranded generation cost recovery, including the generation securitization, wholesale capacity auction true-up, fuel and clawback transition charge, and related carrying costs.
- Fuel cost volatility and fuel cost recovery.
- Financing and recovering the cost of capital expenditures, including environmental and new technology.

RESULTS OF OPERATIONS

<u>Segments</u>
In 2004, AEP's principal operating business segments and their major activities were:

- Utility Operations:
  - Domestic generation of electricity for sale to retail and wholesale customers
  - Domestic electricity transmission and distribution
- Investments – Gas Operations: (a)
  - Gas pipeline and storage services

- Investments – UK Operations: (b)
  - Generation of electricity in the U.K. for sale to wholesale customers
  - Coal procurement and transportation to our plants
- Investments – Other: (c)
  - Bulk commodity barging operations, wind farms, independent power producers and other energy supply-related businesses

(a) LIG Pipeline Company and its subsidiaries, including Jefferson Island Storage & Hub LLC, were classified as discontinued operations during 2003 and were sold during 2004. 98% of the remaining HPL-related gas assets were sold during the first quarter of 2005.
(b) UK Operations were classified as discontinued during 2003 and substantially all operations were sold during 2004.
(c) Four independent power producers were sold during 2004.

Our consolidated Net Income (Loss) for the years ended December 31, 2004, 2003 and 2002 were as follows (Earnings and Average Shares Outstanding in millions):

	2004		2003		2002	
	Earnings	**EPS**	**Earnings**	**EPS**	**Earnings**	**EPS**
Utility Operations	$ 1,171	$ 2.96	$ 1,219	$ 3.17	$ 1,154	$ 3.47
Investments – Gas Operations	(51)	(0.13)	(290)	(0.76)	(99)	(0.29)
Investments – Other	78	0.20	(278)	(0.72)	(522)	(1.58)
All Other (a)	(71)	(0.18)	(129)	(0.34)	(48)	(0.14)
Income Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes	1,127	2.85	522	1.35	485	1.46
Investments – Gas Operations	(12)	(0.03)	(91)	(0.24)	8	0.02
Investments – UK Operations	91	0.23	(508)	(1.32)	(472)	(1.42)
Investments – Other	4	0.01	(6)	(0.01)	(190)	(0.57)
Discontinued Operations, Net of Tax	83	0.21	(605)	(1.57)	(654)	(1.97)
Extraordinary Loss on Texas Stranded Cost Recovery – Utility Operations, Net of Tax	(121)	(0.31)	-	-	-	-
Utility Operations	-	-	236	0.61	-	-
Investments – Gas Operations	-	-	(22)	(0.05)	-	-
Investments – UK Operations	-	-	(21)	(0.05)	-	-
Investments - Other	-	-	-	-	(350)	(1.06)
Cumulative Effect of Accounting Changes, Net of Tax	-	-	193	0.51	(350)	(1.06)
Net Income (Loss)	$ 1,089	$ 2.75	$ 110	$ 0.29	$ (519)	$ (1.57)
Weighted Average Shares Outstanding		396		385		332

(a) All Other includes the Parent's interest income and expense, as well as other nonallocated costs.

2004 Compared to 2003

Income Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes in 2004 increased $605 million compared to 2003 due to increased retail margins and stranded generation carrying cost deferrals at TCC in our Utility Operations, improved margins and lower impairments in our Gas Operations and Investments – Other segments, gains realized on the sale of assets, and lower provisions for penalties and other expenses booked by the Parent. These increases were offset, in part, by decreased margins due to the divestiture of Texas generation assets, the loss of the capacity auction true-up revenues in Texas, and higher operations and maintenance expense, all occurring in our Utility Operations segment.

Our Net Income for 2004 of $1,089 million, or $2.75 per share, includes income, net of tax, on discontinued operations of $83 million, resulting primarily from a gain on the sale of our UK Operations, and an extraordinary loss of $121 million, net of tax, which represents a provision for probable disallowance to the stranded cost net regulatory assets of TCC based on PUCT orders in nonaffiliated true-up proceedings. Our Net Income for 2003 of $110 million, or $0.29 per share, includes a $605 million loss, net of tax, on discontinued operations and $193 million of income, net of tax, from the cumulative effect of changing our accounting for asset retirement obligations and for certain trading activities.

Average shares outstanding increased to 396 million in 2004 from 385 million in 2003 due to a common stock issuance in 2003 and common shares issued related to our incentive compensation plans. The additional average shares outstanding decreased our 2004 earnings per share by $0.08.

2003 Compared to 2002

Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect of Accounting Changes in 2003 increased compared to 2002 due to increased wholesale earnings, lower impairment and other charges, and reduced operations and maintenance expenses. This increase was offset, in part, by milder summer weather and continuing weakness in the economy. Our Net Income for 2003 of $110 million, or $0.29 per share, includes a $605 million loss, net of tax, on discontinued operations and $193 million of income, net of tax, from the cumulative effect of FASB-required changes to our accounting for asset retirement obligations and for certain trading activities. Our Net Loss for 2002 of $519 million, or ($1.57) per share, includes a $654 million loss, net of tax, from discontinued operations and a $350 million, net of tax, charge for implementing a newly issued accounting pronouncement related to the impairment of goodwill.

In the fourth quarter of 2003 we concluded that the UK Operations and LIG were not part of our core business and we began actively marketing each of these investments. The UK Operations consisted of generation and trading operations that sell to wholesale customers. LIG's operations included 2,000 miles of intrastate gas pipelines in Louisiana and 9 Bcf of natural gas storage capacity. Poor market conditions also affected our merchant generation, other gas pipeline and storage assets, goodwill associated with these investments and various other assets. Based on market factors, as measured by a combination of indicative bids from unrelated interested buyers, independent appraisals, and estimates of cash flows, we recognized impairment losses of $960 million, net of tax.

Average shares outstanding increased to 385 million in 2003 from 332 million in 2002 due to a common stock issuance in March 2003. The additional average shares outstanding decreased our 2003 earnings per share by $0.04.

Our results of operations are discussed below according to our operating segments.

Utility Operations

	2004	2003	2002
		(in millions)	
Revenues	$ 10,633	$ 11,015	$ 10,491
Fuel and Purchased Power	3,615	3,746	3,132
Gross Margin	7,018	7,269	7,359
Depreciation and Amortization	1,256	1,250	1,276
Other Operating Expenses	3,772	3,554	3,811
Operating Income	1,990	2,465	2,272
Other Income (Expense), Net	353	27	170
Interest Charges and Preferred Stock Dividend Requirements	616	664	642
Income Tax Expense	556	609	646
Income Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Charges	$ 1,171	$ 1,219	$ 1,154

Summary of Selected Sales Data
For Utility Operations
For the Years Ended December 31, 2004, 2003 and 2002

	2004	2003	2002
Energy Summary		(in millions of KWH)	
Retail:			
Residential	45,770	45,308	37,900
Commercial	37,204	36,798	30,380
Industrial	51,484	49,446	51,491
Miscellaneous	3,099	3,026	2,261
Subtotal	137,557	134,578	122,032
Texas Retail and Other	925	2,896	18,162
Total	138,482	137,474	140,194
Wholesale	82,870	72,977	70,661

	2004	2003	2002
Weather Summary		(in degree days)	
Eastern Region			
Actual – Heating	2,991	3,219	2,886
Normal – Heating (a)	3,086	3,075	3,071
Actual – Cooling	876	756	1,247
Normal – Cooling (a)	974	976	969
Western Region (b)			
Actual – Heating	1,382	1,554	1,566
Normal – Heating (a)	1,624	1,622	1,622
Actual – Cooling	2,005	2,144	2,233
Normal – Cooling (a)	2,149	2,138	2,128

(a) Normal Heating/Cooling represents the 30-year average of degree days.
(b) Western Region statistics represent PSO/SWEPCo customer base only.

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31, 2004
Income from Utility Operations Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2003		$ 1,219
Changes in Gross Margin:		
Retail Margins	65	
Texas Supply Margins	(105)	
Wholesale Capacity Auction True-up Revenues	(215)	
Off-System Sales	10	
Other Revenue	(6)	
		(251)
Changes in Operating and Other Expenses:		
Operations and Maintenance	(205)	
Asset Impairments and Other Related Charges	10	
Depreciation and Amortization	(6)	
Taxes, Other	(23)	
Carrying Costs on Texas Stranded Costs	302	
Other Income (Expense), Net	24	
Interest Charges	48	
		150
Income Tax Expense		53
Year Ended December 31, 2004		$ 1,171

Income from Utility Operations Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes decreased $48 million to $1,171 million in 2004. Key drivers of the decrease include a $251 million decrease in gross margin; offset in part by a $150 million decrease in operating and other expenses and a $53 million decrease in income tax expense.

The major components of the net decrease in gross margin, defined as utility revenues net of related fuel and purchased power, were as follows:

- The increase in retail margins of our utility business over the prior year was due to increased demand in both the East and the West as a consequence of higher usage in most classes and customer growth in the residential and commercial classes. Commercial and industrial demand also increased, resulting from the economic recovery in our regions. Milder weather during the summer months of 2004 partially offset these favorable results.
- Our Texas Supply business experienced a $105 million decrease in gross margin principally due to the partial divestiture of a portion of TCC's generation assets to support Texas stranded cost recovery. This resulted in higher purchased power costs to fulfill contractual commitments.
- Beginning in 2004, the wholesale capacity auction true-up ceased per the Texas Restructuring Legislation. Related revenues are no longer recognized, resulting in $215 million of lower regulatory asset deferrals in 2004. For the years 2003 and 2002, we recognized the revenues for the wholesale capacity auction true-up for TCC as a regulatory asset for the difference between the actual market prices based upon the state-mandated auction of 15% of generation capacity and the earlier estimate of market price used in the PUCT's excess cost over market model.
- Margins from off-system sales for 2004 were $10 million higher than in 2003 due to favorable optimization activity, somewhat offset by lower volumes.

Utility Operating and Other Expenses changed between the years as follows:

- Operations and Maintenance expense increased $205 million due to a $110 million increase in generation expense primarily due to an increase in maintenance outage weeks in 2004 as compared to 2003 and increases in related removal and chemical costs, PJM expenses and operating expenses for the Dow Plaquemine Plant. Additionally, distribution maintenance expense increased $54 million from system improvement and reliability work and damage repair resulting primarily from major ice storms in our Ohio service territory during December 2004. Other increases of $81 million include ERCOT and transmission cost of service adjustments in 2004 and increased employee benefits, insurance, and other administrative and general expenses magnified by favorable adjustments in 2003. These increases were offset, in part, by $40 million due to the conclusion in 2003 of the amortization of our deferred Cook nuclear plant restart expenses.
- 2003 included a $10 million impairment at Blackhawk Coal Company, a nonoperating wholly-owned subsidiary of I&M, which holds western coal reserves.
- Depreciation and Amortization expense increased $6 million primarily due to a higher depreciable asset base, including the addition of capitalized software costs, increased amortization of regulatory assets, and the consolidation in July 2003 of JMG by OPCo (which had no impact on net income). These increases more than offset the decrease in expense at TCC, which is due primarily to the cessation of depreciation on plants classified as held for sale.
- Taxes Other Than Income Taxes increased $23 million due to increased property tax values and assessments, higher revenue taxes due to the increase in KWH sales, and favorable prior year franchise tax adjustments.
- Carrying Costs on Texas Stranded Costs of $302 million represent TCC's debt component of the carrying costs accrued on its net stranded generation costs and its capacity auction true-up asset (see "Texas Restructuring" and "Texas True-Up Proceedings" under Customer Choice and Industry Restructuring).
- Interest Charges decreased $48 million from the prior period primarily due to refinancings of higher coupon debt at lower interest rates.
- Income Tax expense decreased $53 million due to the decrease in pretax income and tax return adjustments.

2003 Compared to 2002

Reconciliation of Year Ended December 31, 2002 to Year Ended December 31, 2003
Income from Utility Operations Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2002		$ 1,154
Changes in Gross Margin:		
Retail Margins	(145)	
Texas Supply	(85)	
Wholesale Capacity Auction Revenues	(44)	
Off-System Sales	162	
Other Wholesale Transactions	(70)	
Other Revenue	92	
		(90)
Changes in Operating and Other Expenses:		
Operations and Maintenance	183	
Asset Impairments and Other Related Charges	43	
Depreciation and Amortization	26	
Taxes, Other	31	
Other Income (Expense), Net	(143)	
Interest Charges	(22)	
		118
Income Tax Expense		37
Year Ended December 31, 2003		$ 1,219

Income from Utility Operations Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes increased $65 million to $1,219 million in 2003. Key drivers of the increase include a $118 million decrease in operating and other expenses and a $37 million decrease in income tax expense; offset in part by a $90 million decrease in gross margin.

The major components of our decrease in gross margin, defined as utility revenues net of related fuel and purchased power, were as follows:

- The decrease in retail margins from the prior year was due to lower retail demand from mild weather primarily in the East, and lower industrial demand in both the East and West service territories primarily due to the continued slow economic recovery in 2003.
- Our Texas Supply business experienced a decrease in gross margin principally due to provisions for probable final Texas fuel and off-system sales disallowances of $102 million and the loss of margin contributions from two Texas Retail Electric Providers (REPs) sold to Centrica in December 2002. The demand from the two REPs was replaced, in part, with a power supply contract with Centrica that extended through 2004.
- In 2003 and 2002, we recognized the revenues for the wholesale capacity auction true-up at TCC as a regulatory asset representing the difference between the actual market prices based upon state-mandated auctions of 15% of economically available generation capacity and the earlier estimate of market prices used in the PUCT's excess cost over market model. The amount recognized in 2003 was $218 million, or $44 million less than in 2002.
- Margins from off-system sales for 2003 improved by $162 million over 2002 due to increased volumes, higher prices, and plant availability.

- Other wholesale transactions represent the transition electric trading book, associated with our decision to exit from markets where we do not own assets. During the fourth quarter of 2002, we exited trading activities that were not related to the sale of power from owned-generation. This reduced comparative 2003 utility earnings by approximately $70 million.
- Other revenue includes transmission revenues, third party revenues and miscellaneous service revenues. Transmission revenues were $45 million higher than the prior year primarily due to the effect of higher off-system sales volumes. Service revenues exceeded the prior year by $47 million primarily due to higher reconnect, temporary service fees, rental on pole attachments, transmission rentals, forfeited discounts, and other miscellaneous items.

Utility Operating and Other Expenses changed between the years as follows:

- Maintenance and Other Operation expenses decreased $183 million due to our continued efforts to reduce costs where practical, primarily administrative and general expenses, labor and employee related expenses, of approximately $120 million. The sale of the Texas REPs reduced expenses supporting the back office by $75 million in 2003, and unfavorable severance costs in 2002 contributed to the period-to-period favorable variance by $65 million. These decreases were offset, in part, by approximately $24 million in damage repair as a result of severe storms in the Midwest, and higher pension and postretirement benefit costs of approximately $60 million in 2003.
- Asset Impairments and Other Related Charges decreased $43 million from the prior year. 2002 included $38 million in impairments of certain moth-balled Texas gas plants, all related to TNC, a $12 million loss of investment value in some early-stage start up technologies, and a $3 million loss of investment value in water heater assets. Asset impairments in 2003 at Blackhawk Coal Company were $10 million.
- Depreciation and Amortization expense decreased $26 million primarily due to the change in our accounting for asset retirement obligations. The change caused similar offsetting increases in Maintenance and Other Operation expense.
- The decrease in Taxes, Other was primarily due to reduced gross receipts tax as a result of the sale of the Texas REPs and prior period franchise tax return true-ups.
- Other Income (Expense), Net decreased $143 million primarily due to a net gain on sale of the Texas REPs in 2002.
- Interest Charges increased $22 million from the prior period due to expensing debt reacquisition costs previously deferred under the regulatory accounting model and the consolidation in July 2003 of JMG by OPCo (which had no impact on net income), as well as the maturity of short-term debt.
- Income Tax expense decreased $37 million primarily due to state tax return adjustments partially offset by higher pretax income.

Investments – Gas Operations

	2004	2003	2002
		(in millions)	
Revenues	$ 3,114	$ 3,126	$ 2,283
Purchased Gas	2,955	2,995	2,171
Gross Margin	159	131	112
Operating Expenses	144	484	227
Operating Income (Loss)	15	(353)	(115)
Other Income (Expense), Net	(33)	(8)	(4)
Interest Charges and Minority Interest in Finance Subsidiary	57	56	50
Income Tax Benefit	24	127	70
Net Loss Before Discontinued Operations and Cumulative Effect of Accounting Changes	$ (51)	$ (290)	$ (99)

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31,2004
Loss from Investments – Gas Operations Before Discontinued Operations and Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2003		$ (290)
Change in Gross Margin		28
Changes in Operating And Other Expenses:		
Operations and Maintenance	21	
Depreciation and Amortization	7	
Taxes, Other	(3)	
Other Income (Expense), Net	(25)	
Interest Charges	(1)	
		(1)
Asset Impairments and Other Related Charges		315
Income Tax Benefit		(103)
Year Ended December 31, 2004		$ (51)

Our loss from Gas Operations before discontinued operations and cumulative effect of accounting changes decreased $239 million to $51 million in 2004. The key driver of the decrease was $315 million of impairments recorded in 2003, partially offset by a $103 million decrease in income tax benefit principally related to the impairments.

The major components of the net increase in gross margin of $28 million, defined as gas revenues net of related purchased gas are as follows:

- 2003 included losses of $31 million related to the servicing of a single contract.
- Pipeline and pipeline optimization margins improved by $24 million.
- Storage margins decreased by $53 million, largely due to timing on recognition of storage margins.
- Prior year transitional gas trading activities yielded losses of $26 million.

Gas Operating and Other Expenses remained flat year-over-year. However, significant line-item changes are as follows:

- Operations and Maintenance expenses decreased $21 million as a result of gas trading activities that have since been ceased.
- Depreciation and Amortization expense decreased $7 million primarily due to the 2003 asset impairments.
- Other Income (Expense), Net decreased $25 million primarily due to the write-off of stranded intercompany debt between a discontinued operation and its parent.

2003 Compared to 2002

Reconciliation of Year Ended December 31, 2002 to Year Ended December 31, 2003
Loss from Investments – Gas Operations Before Discontinued Operations and Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2002		$ (99)
Change in Gross Margin		19
Change in Operating And Other Expenses:		
Operations and Maintenance	60	
Depreciation and Amortization	(5)	
Taxes, Other	3	
Other Income (Expense), Net	(4)	
Interest Charges	(6)	
		48
Asset Impairments and Other Related Charges		(315)
Income Tax Benefit		57
Year Ended December 31, 2003		$ (290)

The loss from our Gas Operations before discontinued operations and cumulative effect of accounting changes of $290 million increased $191 million from 2002. This increase is primarily due to impairments recorded to reflect the reduction in the value of our gas assets. In the fourth quarter of 2003, we recognized impairments and other related charges of $315 million associated with HPL assets and goodwill based on market indicators supported by indicative bids received for LIG. These bids led us to conclude that purchasers were no longer willing to pay higher multiples for historic cash flows which included trading activities. Our previous operating strategy included higher risk tolerances associated with trading activities in order to achieve such operating results.

Partially offsetting the 2003 impairments, Gas Operations earnings increased $124 million year-over-year as a result of the following:

- Improvement in the transition gas segment margins of $62 million due to prior year losses in the options trading portfolio and lower operating expenses of $43 million.
- Decline in trading optimization of $43 million due to lower risk tolerances and limits in 2003 as compared to 2002.
- 2003 included losses of $31 million related to the servicing of a single contract.
- A $57 million increase in income tax benefit due to the increase in pretax losses.

Investments – UK Operations

2004 Compared to 2003

Income from our Investments – UK Operations segment (all classified as Discontinued Operations) increased to $91 million in income, which includes a gain on sale of $128 million in 2004, compared with a loss of $508 million in 2003, before the cumulative effect of accounting change. During late 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. In July 2004, we completed the sale of substantially all operations and assets within our Investments – UK Operations segment.

2003 Compared to 2002

The loss before cumulative effect of accounting change from our UK Operations of $508 million for 2003 increased by $36 million from 2002 due primarily to a $375 million, net of tax, impairment and other related charges recorded during the fourth quarter of 2003 compared with a net of tax impairment of $414 million recorded in 2002. During 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. As a result, we wrote down our UK investment based on bids received from interested, unrelated buyers. The 2003 loss also includes $157 million of pretax losses associated with commitments for below-market forward sales of power, which went beyond the date of the anticipated sale of these plants. We also experienced operating losses as a result of the deterioration of pretax trading margins of $83 million associated with U.K. power and $29 million associated with coal and freight.

Investments – Other

2004 Compared to 2003

Income before discontinued operations from our Investments – Other segment increased from a loss of $278 million in 2003 to income of $78 million in 2004.

The key components of the increase in income were as follows:

- We recorded an after tax gain of approximately $64 million resulting from the sale in July 2004 of our ownership interests in our two independent power producers in Florida (Mulberry and Orange).
- We recorded an after tax gain of approximately $31 million resulting from the sale of our 50% interest in South Coast Power Limited, owner of the Shoreham Power Station in the U.K.
- Our results in 2004 did not include $257 million of after tax impairments recorded in 2003, related to our investment in the Colorado IPPs, AEP Coal and the Dow power generation facility.
- Our AEP Texas Provider of Last Resort (POLR) entity recorded a $6 million after tax provision for uncollectible receivables in 2003.
- AEP Resources decreased its loss by $33 million in 2004 versus 2003, primarily due to lower interest expense of $19 million resulting from equity capital infusions in mid and late 2003 that were used to reduce debt and other corporate borrowings and $6 million related to increased earnings from Bajio.
- AEP Pro Serv reduced losses from $6 million to $1 million of income, primarily due to operations winding down in 2004.

Offsetting these increases was the absence during 2004 of a $31 million gain recorded in 2003 primarily related to the sale of Mutual Energy, AEP's Texas REP, and a $7 million decrease in net income as a result of having sold four of our IPPs in 2004.

Discontinued operations includes the Eastex Cogeneration facility, which was sold in 2003 and Pushan Power Plant, which was sold in March 2004.

2003 Compared to 2002

The loss before discontinued operations and cumulative effect of accounting changes from our Investments - Other segment decreased by $244 million to $278 million in 2003. The decrease was primarily due to asset impairment charges of $257 million, net of tax, recorded in 2003 compared to impairments of $392 million, net of tax, recorded in 2002. Impairments in 2003 included losses of $46 million, net of tax, for two of our independent generation facilities due to market conditions in 2003; $168 million, net of tax, for the Dow facility due to the current market conditions and litigation; and coal mining asset impairments of $44 million, net of tax, based on bids from unrelated parties. We also had lower international development costs and reduced interest expenses during 2003.

All Other

2004 Compared to 2003

The Parent's 2004 loss decreased $58 million from 2003 due to a $40 million provision for penalties booked in 2003, compared to $20 million in 2004, a $12 million decrease in expenses primarily resulting from lower insurance premiums and lower general advertisement expenses in 2004 and a $20 million decrease in income taxes related to federal tax accrual adjustments. Interest income was $9 million lower in the current period due to lower cash balances, along with higher interest rates on invested funds in 2003. Additionally, parent guarantee fee income from subsidiaries was $4 million lower due to the reduction of trading activities. There is no effect on consolidated net income for this item.

2003 Compared to 2002

The Parent's 2003 loss increased $81 million over 2002 primarily from higher interest costs due to increased long-term debt at the parent level and reduced reliance on short-term borrowings as well as a $40 million provision for penalties booked in 2003.

Income Taxes

The effective tax rates for 2004, 2003 and 2002 were 33.5%, 40.3% and 38.8%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, energy production credits, amortization of investment tax credits, and other state income tax and federal income tax adjustments. The decrease in the effective tax rate in 2004 versus the comparative period is primarily due to more favorable federal income tax adjustments in 2004 versus 2003 and changes in permanent differences. The effective tax rates remained relatively flat between 2002 and 2003.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2004, we improved our financial condition as a consequence of the following actions and events:

- We reduced short-term debt by $303 million, terminated our Euro revolving credit facility, completed approximately $2.3 billion of long-term debt redemptions, including optional redemptions such as our Steelhead financing, and funded $770 million of debt maturities; and
- We maintained stable credit ratings across the AEP System. Moody's Investor Services assigned a positive outlook on AEP Inc.'s ratings, while the rated subsidiaries continued to have ratings with stable outlooks.

Capitalization ($ in millions)

	2004		2003	
Common Equity	$ 8,515	40.6 %	$ 7,874	35.1 %
Preferred Stock	61	0.3	61	0.3
Preferred Stock (Subject to Mandatory Redemption)	66	0.3	76	0.3
Long-term Debt, including amounts due within one year	12,287	58.7	14,101	62.8
Short-term Debt	23	0.1	326	1.5
Total Capitalization	$ 20,952	100.0 %	$ 22,438	100.0 %

Our $2.6 billion in cash flows from operations, combined with our reduction in cash expenditures for investments in discontinued operations, the proceeds from asset sales, a reduction in the dividend beginning in the second quarter of 2003 and the use of a portion of our cash on hand, allowed us to reduce long-term debt by $1.8 billion and short-term debt by $303 million.

Our common equity increased due to earnings exceeding the amount of dividends paid in 2004, a discretionary $200 million cash contribution to our pension fund, which allowed us to remove a portion of the charge to equity related to the underfunded plan, and the issuance of $17 million of new common equity (related to our incentive compensation plans).

As a consequence of the capital changes during 2004, we improved our ratio of debt to total capital from 64.6% to 59.1% (preferred stock subject to mandatory redemption is included in the debt component of the ratio).

In February 2005, our Board of Directors authorized us to repurchase up to $500 million of our common stock from time to time through 2006.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to maintaining adequate liquidity.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2004, our available liquidity was approximately $3.3 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Lines of Credit	$ 1,000	May 2005
Lines of Credit	750	May 2006
Lines of Credit	1,000	May 2007
Letter of Credit Facility	200	September 2006
Total	2,950	
Cash and Cash Equivalents	420	
Total Liquidity Sources	3,370	
Less: AEP Commercial Paper Outstanding	- (a)	
Letters of Credit Outstanding	54	
Net Available Liquidity	$ 3,316	

(a) Amount does not include JMG commercial paper outstanding in the amount of $23 million. This commercial paper is specifically associated with the Gavin scrubber and does not reduce AEP's available liquidity. The JMG commercial paper is supported by a separate letter of credit facility not included above.

During the second quarter of 2005, we intend to replace our $1 billion credit facility expiring in May 2005 and our $750 million credit facility expiring in May 2006 with a $1.5 billion five-year credit facility.

Debt Covenants

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 other capital under these covenants is contractually defined. At December 31, 2004, this percentage was 54.1%. Nonperformance of these covenants may result in an event of default under these credit agreements. At December 31, 2004, we complied with the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or those of certain of our 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 permit the lenders to declare the amounts outstanding thereunder payable.

Our revolving credit facilities generally prohibit new borrowings if we experience a material adverse change in our business or operations. We may, however, make new borrowings under these facilities if we experience a material adverse change so long as the proceeds of such borrowings are used to repay outstanding commercial paper.

Under an SEC order, AEP and its utility subsidiaries cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% (25% for TCC) of its capital. In addition, this order restricts AEP and the utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization. At December 31, 2004, we were in compliance with this order.

Nonutility Money Pool borrowings, Utility Money Pool borrowings and external borrowings may not exceed SEC or state commission authorized limits. At December 31, 2004, we had not exceeded the SEC or state commission authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 379 consecutive quarters. The Board of Directors, at its January 2005 meeting, declared a quarterly dividend of $0.35 a share, payable March 10, 2005 to shareholders of record on February 10, 2005. 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. The timing of any dividend increase could depend upon the resolution of certain issues, including our planned divestitures and the results of our Texas rate and true-up proceedings. We hope to be able to recommend to the Board of Directors gradual, sustainable increases in our common stock dividend from its current level of 35 cents per share per quarter.

PUHCA prohibits our subsidiaries from making loans or advances to the parent company, AEP. In addition, under PUHCA, AEP and its public utility subsidiaries can pay dividends only out of retained or current earnings.

Credit Ratings

We continue to take steps to improve our credit quality, including executing plans during 2004 to further reduce our outstanding debt through the use of proceeds from our asset divestitures and other available cash.

AEP's ratings have not been adjusted by any rating agency during 2004. On August 2, 2004, Moody's Investors Service (Moody's) changed their outlook on AEP to "positive" from "stable," while keeping the remaining rated subsidiaries on "stable" outlook. The other major rating agencies have AEP and its rated subsidiaries on "stable" outlook.

Our current credit ratings are as follows:

	Moody's	S&P	Fitch
AEP Short Term Debt	P-3	A-2	F-2
AEP Senior Unsecured Debt	Baa3	BBB	BBB

If AEP or any of its rated subsidiaries receive an upgrade from any of the rating agencies listed above, our borrowing costs could decrease. If we receive a downgrade in our credit ratings by one of the nationally recognized rating agencies listed above, our borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Our cash flows are a major factor in managing and maintaining our liquidity strength.

	2004	2003	2002
		(in millions)	
Cash and cash equivalents at beginning of period	$ 976	$ 1,084	$ 163
Net Cash Flows From Operating Activities	2,597	2,308	2,067
Net Cash Flows Used For Investing Activities	(376)	(1,979)	(462)
Net Cash Flows Used For Financing Activities	(2,777)	(437)	(681)
Effect of Exchange Rate Changes on Cash	-	-	(3)
Net Increase (Decrease) in Cash and Cash Equivalents	(556)	(108)	921
Cash and cash equivalents at end of period	$ 420	$ 976	$ 1,084

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to meet other short-term cash needs. We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, 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, 2004, we had credit facilities totaling $2.8 billion to support our commercial paper program. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding mechanisms are arranged. Sources of long-term funding include issuance of common stock or long-term debt and sale-leaseback or leasing agreements. Nonutility Money Pool borrowings, Utility Money Pool borrowings and external borrowings may not exceed SEC authorized limits.

Operating Activities

	2004	2003	2002
		(in millions)	
Net Income (Loss)	$ 1,089	$ 110	$ (519)
Plus: (Income) Loss From Discontinued Operations	(83)	605	654
Income From Continuing Operations	1,006	715	135
Noncash Items Included in Earnings	1,471	1,939	2,676
Changes in Assets and Liabilities	120	(346)	(744)
Net Cash Flows From Operating Activities	$ 2,597	$ 2,308	$ 2,067

2004 Operating Cash Flow

During 2004, our cash flows from operating activities were $2.6 billion consisting of our income from continuing operations of $1 billion and noncash charges of $1.6 billion for depreciation, amortization and deferred taxes. We recorded $302 million in noncash income for carrying costs on Texas stranded cost recovery and recognized an after tax, noncash extraordinary loss of $121 million to provide for probable disallowances to TCC's stranded generation costs. We realized a $159 million gain on sale of assets primarily on the sales of the IPPs and South Coast. We made a $200 million discretionary contribution to our pension trust.

Changes in Assets and Liabilities represent those 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.

Changes in working capital items resulted in cash from operations of $467 million predominantly due to increased accrued income taxes. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since our consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payment will be made in March 2005 when the 2004 federal income tax return extension is filed.

2003 Operating Cash Flow

Our cash flows from operating activities were $2.3 billion for 2003. We produced income from continuing operations of $715 million during the period. Income from continuing operations for 2003 included noncash items of $1.5 billion for depreciation, amortization, and deferred taxes, $193 million for the cumulative effects of accounting changes, and $720 million for impairment losses and other related charges. In addition, there was a current period impact for a net $122 million balance sheet change for risk management contracts that are marked-to-market. These derivative contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The 2003 activity in changes in assets and liabilities relates to a number of items; the most significant of which are:

- Noncash wholesale capacity auction true-up revenues resulting in stranded cost regulatory assets of $218 million, which are not recoverable in cash until the conclusion of our TCC's True-up Proceeding.
- Net changes in accounts receivable and accounts payable of $269 million related, in large part, to the settlement of risk management positions during 2002 and payments related to those settlements during 2003. These payments include $90 million in settlement of power and gas transactions to the Williams Companies. The earnings effects of substantially all payments were reflected on a MTM basis in earlier periods.
- Increases in fuel and inventory levels of $52 million resulting primarily from higher procurement prices.
- Reserves for disallowed deferred fuel costs, principally related to Texas, which will be a component of our Texas True-up Proceedings.

2002 Operating Cash Flow

During 2002, our cash flows from operating activities were $2.1 billion. Income from continuing operations was $135 million during the period. Income from continuing operations for 2002 included noncash items of $1.4 billion for depreciation, amortization, and deferred taxes, $350 million related to the cumulative effect of an accounting change, and $639 million for impairment losses. There was a current period impact for a net $275 million balance sheet change for risk management contracts that were marked-to-market. These contracts have unrealized earnings impacts as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The activity in the asset and liability accounts related to the wholesale capacity auction true-up regulatory asset of $262 million, deposits associated with risk management activities of $136 million, and seasonal increases in our fuel inventories.

Investing Activities

	2004	2003	2002
		(in millions)	
Construction Expenditures	$ (1,693)	$ (1,358)	$ (1,685)
Change in Other Cash Deposits, Net	31	(91)	(84)
Proceeds from Sale of Assets	1,357	82	1,263
Other	(71)	(612)	44
Net Cash Flows Used for Investing Activities	$ (376)	$ (1,979)	$ (462)

In 2004, our cash flows used for investing activities were $376 million. We funded our construction expenditures primarily with cash generated by operations. Our construction expenditures of $1.7 billion were distributed across our system, of which the most significant expenditures were investments for environmental improvements of $350 million and for a high voltage transmission line of $75 million. During 2004, we sold our U.K. generation, Jefferson Island Storage, LIG and certain IPP and TCC generation assets and used the proceeds from the sales of these assets to reduce debt.

Our cash flows used for investing activities were $2 billion in 2003 for increased investments in our U.K. operations and environmental and normal capital expenditures.

In 2002, our cash flows used for investing activities were $462 million as the proceeds received from the sales of SEEBOARD, CitiPower, and the Texas REPs offset a significant portion of our construction expenditures.

We forecast $2.7 billion of construction expenditures for 2005. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

Financing Activities

	2004	2003	2002
		(in millions)	
Issuances of Equity Securities (common stock/equity units)	$ 17	$ 1,142	$ 990
Issuances/Retirements of Debt, net	(2,229)	(727)	(868)
Retirement of Preferred Stock	(10)	(9)	(10)
Retirement of Minority Interest (a)	-	(225)	-
Dividends Paid on Common Stock	(555)	(618)	(793)
Net Cash Flows Used for Financing Activities	$ (2,777)	$ (437)	$ (681)

(a) Minority Interest was reclassified to debt in July 2003 and the related $525 million of debt was repaid in 2004. See "Minority Interest in Finance Subsidiary" section of Note 17.

In 2004, we used $2.8 billion of cash to reduce debt and pay common stock dividends. We achieved our goal of reducing debt below 60% of total capitalization by December 31, 2004. The debt reductions were primarily funded by proceeds from our various divestitures in 2004.

Our cash flows used for financing activities were $437 million during 2003. The proceeds from the issuance of common stock were used to reduce outstanding debt and minority interest in a finance subsidiary.

In 2002, we used $681 million of cash from operations to pay common stock dividends and proceeds from the issuance of equity to repay debt.

The following financing activities occurred during 2004 and 2003:

Common Stock:

- During 2004 and 2003, we issued 841,732 and 23,001 shares of common stock, respectively, under our incentive compensation plans. For 2004, we received net proceeds of $14 million for 525,002 shares. The net proceeds for 2003 were insignificant.
- In March 2003, we issued 56 million shares of common stock at $20.95 per share through an equity offering and received net proceeds of $1.1 billion (net of issuance costs of $36 million). We used the proceeds to pay down both short-term and long-term debt with the balance being held in cash.

Debt:

- During 2004, we issued approximately $1.2 billion of long-term debt, including approximately $318 million of pollution control revenue bonds. The proceeds of these issuances were used to reduce short-term debt, fund long-term debt maturities and fund optional redemptions. In August 2004, Moody's Investor Services upgraded AEP, Inc.'s short-term and long-term debt ratings to a "positive" outlook.
- During 2004, we entered into $530 million notional amount of fixed to floating swaps and unwound $400 million notional amount of swap transactions. The swap unwinds resulted in $9.1 million in cash proceeds. As of December 31, 2004, we had in place interest rate hedge transactions with a notional amount of $515 million in order to hedge a portion of anticipated 2005 issuances.

- During 2004, AEP Credit renewed its sale of receivables agreement for three years and it now expires on August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2004, $435 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.
- In May 2004, we closed on a $1 billion revolving credit facility for AEP, Inc., which replaced a maturing $750 million revolving credit facility. The facility will expire in May 2007. As of December 31, 2004, we had credit facilities totaling $2.8 billion to support our commercial paper program. As of December 31, 2004, we had no commercial paper outstanding related to the corporate borrowing program. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $661 million in June 2004 and the weighted average interest rate of commercial paper outstanding during the year was 1.81%.
- In June 2004, $494 million of five-year floating rate private placement debt was refinanced by Juniper Capital under the lease agreement for our Dow Plaquemine Cogeneration Project. See "Power Generation Facility" section within this "Financial Condition" section.

Our plans for 2005 include the following:

- In January, APCo issued Senior Unsecured Notes in the amount of $200 million at a rate of 4.95%.
- In January, OPCo refinanced $218 million of JMG's Installment Purchase Contracts. The new bonds bear interest at a 35-day auction rate.
- In February, TCC reissued $162 million Matagorda County Navigation District Installment Purchase Contracts due May 1, 2030 that were put to TCC in November 2004. These bonds had not been retired as TCC intended to reissue the bonds at a later date. The original installment purchase contracts were mandatory one-year put bonds with fixed rates of 2.15% for Series A and 2.35% for Series B at the time of the put. The reissued contracts bear interest at 35-day auction rates.
- In June 2002, we issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consists of a forward purchase contract and a senior note. In May 2005, the senior note portion of the equity will be remarketed and the coupon reset. In August 2005, under the terms of the equity units, holders will be required to purchase from us a certain number of shares per unit (1.2225 shares per unit at our current stock price). This would increase our average total shares outstanding from 396 million in 2004 to an estimated 399 million in 2005.
- Quarterly, make discretionary contributions of $100 million to our underfunded pension plans in order to fully fund the plans by the end of 2005.

Minority Interest and Off-balance Sheet Arrangements

We enter into minority interest and off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. The following identifies significant minority interest and off-balance sheet arrangements:

Minority Interest in Finance Subsidiary

- We formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis) in August 2001. As managing member, SubOne consolidated Caddis. Steelhead Investors LLC (Steelhead) was an unconsolidated special purpose entity with no relationship to us or any of our subsidiaries. The money invested in Caddis by Steelhead was loaned to SubOne.
- On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis. As a result, a note payable to Caddis was reported as a component of Long-term Debt, the balance of which was $525 million on December 31, 2003. Due to the prospective application of FIN 46, we did not change the presentation of Minority Interest in Finance Subsidiary in periods prior to July 1, 2003.
- The $525 million Caddis note payable was paid off in 2004 at which time SubOne no longer had any requirements or obligations under the structure described above.

AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. We have no ownership interest in the commercial paper conduits and are not required to consolidate these entities in accordance with GAAP. We continue to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables, and accelerate its cash collections.

During 2004, AEP Credit renewed its sale of receivables agreement through August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2004, $435 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivables less an allowance for anticipated uncollectible accounts.

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 respective company are $1.3 billion.

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. The lease is accounted for as an operating lease with the future payment obligations included in the lease footnote. 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 none of these entities guarantee its debt.

Railcars

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms, for a maximum of twenty years. At this time, we intend to renew the lease for the full twenty years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease with the future payment obligations included in the lease footnote. This operating lease agreement allows us to avoid a large initial capital expenditure, and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over time from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2004, the maximum potential loss was approximately $32 million ($21 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year to a nonaffiliated company under an operating lease. The sublessee may renew the lease for up to three additional one-year terms. AEP has other railcar lease arrangements that do not utilize this type of financing structure.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payments Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Long-term Debt (a)	$ 1,279	$ 2,921	$ 977	$ 7,161	$ 12,338
Short-term Debt (b)	23	-	-	-	23
Preferred Stock Subject to Mandatory Redemption (c)	66	-	-	-	66
Capital Lease Obligations (d)	64	97	51	92	304
Noncancelable Operating Leases (d)	291	505	452	2,181	3,429
Fuel Purchase Contracts (e)	1,954	2,599	1,111	1,367	7,031
Energy and Capacity Purchase Contracts (f)	188	342	219	507	1,256
Construction Contracts for Capital Assets (g)	626	90	-	-	716
Total	$ 4,491	$ 6,554	$ 2,810	$ 11,308	$ 25,163

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.
(b) Represents principal only excluding interest.
(c) See Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries.
(d) See Note 16.
(e) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(f) Represents contractual cash flows of energy and capacity purchase contracts.
(g) Represents only capital assets that are contractual obligations.

As discussed in Note 11 to the Consolidated Financial Statements, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

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, 2004, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millions)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Standby Letters of Credit (a)	$ 103	$ 138	$ -	$ 1	$ 242
Guarantees of the Performance of Outside Parties (b)	10	-	22	109	141
Guarantees of our Performance (c)	439	749	681	8	1,877
Transmission Facilities for Third Parties (d)	45	64	20	24	153
Total Commercial Commitments	$ 597	$ 951	$ 723	$ 142	$ 2,413

(a) We have issued standby letters of credit to third parties. These letters of credit cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in our ordinary course of business. The maximum future payments of these letters of credit are $242 million with maturities ranging from February 2005 to January 2011. As the parent of all of these subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

(b) See Note 8.

(c) We have issued performance guarantees and indemnifications for energy trading, Dow Chemical Company financing, Marine Transportation Pollution Control Bonds and various sale agreements.

(d) As construction agent for third party owners of transmission facilities, we have committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to $8 million and other remedies required by contract terms.

<u>Other</u>

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow) under a 5-year term with three 5-year renewal terms for a total term of up to 20 years. The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004. The initial term of our lease with Juniper (Juniper Lease) commenced on March 18, 2004 and terminates on June 17, 2009. We may extend the term of the Juniper Lease to a total lease term of 30 years. Our lease of the Facility is reported as an owned-asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on our Consolidated Balance Sheets and the obligations under the lease agreement are excluded from the table of future minimum lease payment in Note 16.

Juniper is a nonaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility with debt financing of up to $494 million and equity of up to $31 million from investors with no relationship to AEP or any of AEP's subsidiaries.

The Facility is collateral for Juniper's debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Juniper's funded obligations as a liability of $520 million. Upon expiration of the lease, our actual cash obligation could range from $0 to $415 million based on the fair value of the assets at that time. However, if we default under the Juniper Lease, our maximum cash payment could be as much as $525 million.

We have the right to purchase the Facility for the acquisition cost during the last month of the Juniper Lease's initial term or on any monthly rent payment date during any extended term of the lease. In addition, we may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if we have arranged a sale of the Facility to a nonaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow as described below. If the lease were renewed for up to a 30-year lease term, then at the end of that 30-year term we may further renew the lease at fair market value subject to Juniper's approval, purchase the Facility at its acquisition cost, or sell the Facility, on behalf of Juniper, to an independent third party. If the Facility is sold and the proceeds from the sale are insufficient to pay all of Juniper's acquisition costs, we may be required to make a payment (not to exceed $415 million) to Juniper of the excess of Juniper's acquisition cost over the proceeds from the sale. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report Juniper's funded obligations related to the Facility on our Consolidated Balance Sheets, the fair value of the liability for our guarantee (the $415 million payment discussed above) is not separately reported.

At December 31, 2004, Juniper's acquisition costs for the Facility totaled $520 million, and the total acquisition cost for the completed Facility is currently expected to be approximately $525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR (plus a component for a fixed-rate return on Juniper's equity investment and an administrative charge). Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately $23 million represent future minimum lease payments to Juniper during the initial term. The majority of the payment is calculated using the indexed LIBOR rate (2.55% at December 31, 2004). Annual sublease payments received from Dow are approximately $27 million (substantially based on an adjusted three-month LIBOR rate discussed above).

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW).

OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM (Tractebel SA) has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there were no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable. On January 21, 2005, the District Court granted AEP partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA. The litigation is in the discovery phase, with trial scheduled to begin on March 23, 2005.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the "Commercial Operations Date." Despite OPCo's prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCo's tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for them under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo, (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the District Court that the PPA has been terminated and (iii) would be pursuing against TEM, and Tractebel SA under the guaranty, damages and the full termination payment value of the PPA.

The uncertainty of the litigation between TEM and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power freed up by the TEM contract termination, triggered us to review the project for possible impairment of its reported values. We determined that the value of the Facility was impaired and recorded a $258 million ($168 million net of tax) impairment in December 2003. See "Power Generation Facility" section of Note 10 for further discussion.

Texas REPs

As part of the purchase and sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings from the two REPs above a threshold amount through 2006 in the event the Texas retail market developed increased earnings opportunities. No revenue was recorded in 2004 or 2003 related to these sharing agreements, pending resolution of various contractual matters. We expect to resolve the outstanding matters and record the related revenue in 2005. Management is unable to predict with certainty the amount of revenue that will be recorded.

SIGNIFICANT FACTORS

Progress Made on Announced Divestitures

We continued with our announced plan to divest noncore components of our nonregulated assets and certain Texas generation assets in order to recover stranded generation costs. During 2004, we generated $1.4 billion in proceeds from these dispositions. See Note 10 of our Notes to Consolidated Financial Statements within this Annual Report.

We made progress on our planned divestiture of certain Texas generation assets by (1) announcing in June 2004 and September 2004 that we had signed agreements to sell TCC's 7.81% share of the Oklaunion Power Station to two nonaffiliated co-owners of the plant for approximately $43 million, subject to closing adjustments, (2) announcing in September 2004 that we had signed agreements to sell TCC's 25.2% share of the STP nuclear plant to two nonaffiliated co-owners of the plant for approximately $333 million, subject to closing adjustments, and (3) closing in July 2004 on the sale of TCC's remaining generation assets, including eight natural gas plants, one coal-fired plant and one hydro-electric plant for approximately $428 million, net of adjustments. We expect the sales of Oklaunion and STP to be completed in the first half of 2005. Nevertheless, there could be potential delays in receiving necessary regulatory approvals and clearances or in resolving litigation with a third party affecting Oklaunion which could delay the closings. We will file with the PUCT to recover net stranded costs associated with the sales pursuant to Texas Restructuring Legislation. Stranded costs will be calculated on the basis of all generation assets, not individual plants.

We continue to have discussions with various parties on business alternatives for certain of our other noncore investments, which may result in further dispositions in the future. We are involved in discussions to sell our 50% equity interest in Bajio, a 600 MW natural gas-fired facility in Mexico and our 20% equity interest in Pacific Hydro, an operator of renewable energy facilities in the Pacific Rim.

The ultimate timing for a disposition of one or more of these assets will depend upon market conditions and the value of any buyer's proposal. We believe our remaining noncore assets are stated at fair value. However, we may realize losses from operations or losses or gains upon the eventual disposition of these assets that, in the aggregate, could have a material impact on our results of operations, cash flows and financial condition.

Texas Regulatory Activity

Texas Restructuring

Texas Restructuring Legislation enacted in 1999 provides the framework and timetable to allow retail electricity competition.

The Texas Restructuring Legislation, among other things:

- provides for the recovery of net stranded generation costs and other generation true-up amounts through securitization and nonbypassable wires charges,
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility,
- provides for an earnings test for each of the years 1999 through 2001 and,
- provides for a stranded cost True-up Proceeding after January 10, 2004.

The True-up Proceedings will determine the amount and recovery of:

- net stranded generation plant costs and net generation-related regulatory assets less any unrefunded excess earnings (net stranded generation costs),

- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the projected power costs used in the PUCT's excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up revenues),
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
- final approved deferred fuel balance, and
- net carrying costs on true-up amounts.

TCC's recorded net true-up regulatory asset for amounts subject to approval in the True-up Proceeding is approximately $1.6 billion at December 31, 2004.

The Texas Restructuring Legislation required utilities with stranded generation plant costs to use market-based methods to value certain generation assets for determining stranded generation plant costs. TCC elected to use the sale of assets method to determine the market value of its generation assets for determining stranded generation plant costs. For purposes of the True-up Proceeding, the amount of stranded generation plant costs under this market valuation methodology will be the amount by which the book value of TCC's generation assets exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets.

In December 2003, based on an expected loss from the sale of its generating assets, TCC recognized as a regulatory asset an estimated impairment of approximately $938 million from the sale of all its generation assets. The impairment was computed based on an estimate of TCC's generation assets sales price compared to book basis at December 31, 2003. On July 1, 2004, TCC completed the sale of most of its coal, gas and hydro plants for approximately $428 million, net of adjustments. The closings of the sales of STP and Oklaunion plants are expected to occur in the first half of 2005, subject to resolution of the rights of first refusal issues and obtaining the necessary regulatory approvals. In addition, there could be delays in resolving litigation with a third party affecting Oklaunion. On February 15, 2005, TCC filed with the PUCT requesting a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closings of the sales of all the generation assets. TCC asked the PUCT to rule on the request in April 2005.

On December 17, 2004, the PUCT also issued an Order on Rehearing in the CenterPoint True-Up Proceeding (CenterPoint Order). CenterPoint is a nonaffiliated electric utility in Texas. Among other things, the CenterPoint Order provided certain adjustments to stranded generation plant costs to avoid what the PUCT deemed to be duplicative recovery of stranded costs and the capacity auction true-up amount. The CenterPoint Order also confirmed that stranded costs are to be determined as of December 31, 2001, and identified how carrying costs from that date are to be computed.

In the fourth quarter of 2004, TCC made adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis (instead of December 31, 2003 book basis), including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCC's stranded generation plant costs regulatory asset was reduced by $238 million based on an applicable PUCT duplicate depreciation adjustment in the CenterPoint Order. These adjustments are reflected as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax in our Consolidated Statements of Operations.

In addition to the two items above (the $938 million impairment in 2003 and the $185 million adjustment in 2004), TCC had recorded $121 million of impairments in 2002 and 2003 on its gas-fired plants. Additionally, other miscellaneous items and the costs to complete the sales, which are still ongoing, of $23 million are included in the recoverable stranded generation plant costs of $897 million.

In the CenterPoint Order, the PUCT specified the manner in which carrying costs should be calculated. In December 2004, TCC computed, based on its interpretation of the methodology contained in the CenterPoint Order, carrying costs of $470 million for the period January 1, 2002 through December 31, 2004 on its stranded generation plant costs net of excess earnings and its wholesale capacity auction true-up regulatory assets at the 11.79% overall pretax cost of capital rate in its UCOS rate proceeding. The embedded 8.12% debt component of the carrying cost of $302 million ($225 million on stranded generation plant costs and $77 million on wholesale capacity auction true-up) was recognized in income in December 2004. This amount is included in Carrying Costs on Texas Stranded

Cost Recovery in our Consolidated Statements of Operations. Of the $302 million recorded in 2004, approximately $109 million, $105 million and $88 million related to the years 2004, 2003 and 2002, respectively. The remaining equity component of $168 million will be recognized in income as collected. TCC will continue to accrue a carrying cost at the rate set forth above until it recovers its approved net true-up regulatory asset. If the PUCT further adjusts TCC's net true-up regulatory asset in TCC's True-up Proceeding, the carrying cost will also be adjusted.

When the True-up Proceeding is completed, TCC intends to file to recover PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through nonbypassable transition charges and competition transition charges in the regulated T&D rates. TCC will seek to securitize the approved net stranded generation costs plus related carrying costs. The securitizable portion of this net true-up regulatory asset, which consists of net stranded generation costs plus related carrying costs, was $1.4 billion at December 31, 2004. The other approved net true-up items will be recovered or refunded over time through a nonbypassable competition transition wires charge or credit inclusive of a carrying cost. We expect that TCC's True-up Proceeding filing will seek to recover an amount in excess of the total of its recorded net true-up regulatory asset through December 31, 2004. The PUCT will review TCC's filing and determine the amount for the recoverable net true-up regulatory assets.

Due to differences between CenterPoint's and TCC's facts and circumstances, the lack of direct applicability of certain portions of the CenterPoint Order to TCC and the unknown nature of future developments in TCC's True-up Proceeding, we cannot, at this time, determine if TCC will incur additional disallowances in its True-up Proceeding. We believe that our recorded net true-up regulatory asset at December 31, 2004 is in compliance with the Texas Restructuring Legislation, and the applicable portions of the CenterPoint Order and other nonaffiliated true-up orders, and we intend to seek vigorously its recovery. If, however, we determine that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.6 billion at December 31, 2004 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount, which could have a material adverse effect on future results of operations, cash flows and possibly financial condition. To the extent decisions in the TCC True-up Proceeding differ from management's interpretation of the Texas Restructuring Legislation and its evaluation of the applicable portions of the CenterPoint and other true-up orders, additional material disallowances are possible.

See "TEXAS RESTRUCTURING" section of Note 6 for further discussion of Texas Regulatory Activity.

TCC Rate Case

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCC's proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%.

In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCC's requested $67 million annual rate increase. Their recommendations ranged from a decrease in annual existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. Hearings were held in March 2004. In May 2004, TCC agreed to a nonunanimous settlement on cost of capital including capital structure and return on equity with all but two parties in the proceeding. TCC agreed that the return on equity should be established at 10.125% based upon a capital structure with 40% equity resulting in a weighted cost of capital of 7.475%. The settlement and other agreed adjustments reduced TCC's rate request from an increase of $67 million to an increase of $41 million.

On July 1, 2004, the ALJs who heard the case issued their recommendations, which included a recommendation to approve the cost of capital settlement. The ALJs recommended that an issue related to the allocation of consolidated tax savings to the transmission and distribution utility be remanded back to the ALJs for additional evidence. On July 15, 2004, the PUCT remanded this issue to the ALJs. On August 19, 2004, in a separate ruling, the PUCT remanded six other issues to the ALJs requesting revisions to clarify and support the recommendations in the Proposal for Decision (PFD).

The PUCT ordered TCC to calculate its revenue requirements based upon the recommendations of the ALJs. On July 21, 2004, TCC filed its revenue requirements based upon the recommendations of the ALJs. According to TCC's calculations, the ALJs' recommendations would reduce TCC's annual existing rates between $33 million and $43 million depending on the final resolution of the amount of consolidated tax savings.

On November 16, 2004, the ALJs issued their PFD on remand, increasing their recommended annual rate reduction to a range of $51 million to $78 million, depending on the amount disallowed related to affiliated AEPSC billed expenses. At the January 13, 2005 and January 27, 2005 open meetings, the Commissioners considered a number of issues, but deferred resolution of the affiliated AEPSC billed expenses issue, among other less significant issues, until after additional hearings scheduled for early March 2005. Adjusted for the decisions announced by the Commissioners in January 2005, the ALJs' disallowance would yield an annual rate reduction of a range of $48 million to $75 million. If TCC were to prevail on the affiliated expenses issue and all remaining issues, the result would be an annual rate increase of $6 million. When issued, the PUCT order will affect revenues prospectively. An order reducing TCC's rates could have a material adverse effect on future results of operations and cash flows.

Ohio Regulatory Activity

The Ohio Electric Restructuring Act of 1999 (Ohio Act) provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed rate stabilization plans with the PUCO addressing prices for the three-year period following the end of the MDP, January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. On January 26, 2005, the PUCO approved the plans with some modifications.

The approved plans include annual, fixed increases in the generation component of all customers' bills (3% a year for CSPCo and 7% a year for OPCo) in 2006, 2007 and 2008. The plan also includes the opportunity to annually request an additional increase in supply prices averaging up to 4% per year for each company to recover certain new governmentally mandated increased expenditures set out in the approved plan. The plans maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level in effect on December 31, 2005. Such rates could be adjusted with PUCO approval for specified reasons. Transmission charges could also be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion and ancillary services. The approved plans provide for the continued amortization and recovery of stranded transition generation-related regulatory assets. The plans, as modified by the PUCO, require CSPCo and OPCo to allot a combined total of $14 million of previously provided unspent shopping incentives for the benefit of their low-income customers and economic development over the three-year period ending December 31, 2008 which will not have an effect on net income. The plans also authorized each company to establish unavoidable riders applicable to all distribution customers in order to be compensated in 2006 through 2008 for certain new costs incurred in 2004 and 2005 of fulfilling the companies' Provider of Last Resort (POLR) obligations. These costs include RTO administrative fees and congestion costs net of financial transmission revenues and carrying cost of environmental capital expenditures. As a result, in 2005, CSPCo and OPCo expect to record regulatory assets of approximately $8 million and $21 million, respectively for the subject costs related to 2004 and $14 million and $52 million, respectively, for expected subject costs related to 2005. These regulatory assets totaling $22 million for CSPCo and $73 million for OPCo will be amortized as the costs are recovered through POLR riders in 2006 through 2008. The riders, together with the fixed annual increases in generation rates are estimated to provide additional cumulative revenues to CSPCo and OPCo of $190 million and $500 million, respectively, in the three-year period ended December 31, 2008. Other revenue increases may occur related to other provisions of the plans discussed above.

On February 25, 2005, various intervenors filed Applications for Rehearing with the PUCO regarding their approval of the rate stabilization plans. Management expects the PUCO to address the applications before the end of March 2005. Management cannot predict the ultimate impact these proceedings will have on the results of operations and cash flows.

See "OHIO RESTRUCTURING" section of Note 6 for further discussion of Ohio Regulatory Activity.

Oklahoma Regulatory Activity

PSO Fuel and Purchased Power

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed testimony in February 2004.

An intervenor and the OCC Staff filed testimony in April 2004. The intervenor suggested that $9 million related to the 2002 reallocation not be recovered from customers. The Attorney General of Oklahoma also filed a statement of position, indicating allocated off-system sales margins between and among AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and, if corrected, could more than offset the $44 million 2002 reallocation under-recovery. The intervenor and the OCC Staff also argued that off-system sales margins were allocated incorrectly. The intervenors' reallocation of such margins would reduce PSO's recoverable fuel costs by $7 million for 2000 and $11 million for 2001, while under the OCC Staff method, the reduction for 2001 would be $9 million. The intervenor and the OCC Staff also recommended recalculation of PSO's fuel costs for years subsequent to 2001 using the same revised methods. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were under the jurisdiction of the OCC because they relate to FERC-approved allocation agreements. As a result, the ALJ ordered that the parties brief the jurisdictional issue. After reviewing the briefs, the ALJ recommended that the OCC lacks authority to examine whether PSO deviated from the FERC allocation methodology and that any such complaints should be addressed at the FERC. In January 2005, the OCC conducted a hearing on the jurisdictional matter and a ruling is expected in the near future. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

PSO Rate Review

In February 2003, the OCC Staff filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003 and June 2004, PSO filed financial information and supporting testimony in response to the OCC Staff's request. PSO's initial response indicated that its annual revenues were $36 million less than costs. The June 2004 filing updated PSO's request and indicated a $41 million revenue deficiency. As a result, PSO sought OCC approval to increase its base rates by that amount, which is a 3.9% increase over PSO's existing revenues.

In August 2004, PSO filed a motion to amend the timeline to consider new service quality and reliability requirements, which took effect on July 1, 2004. Also in August 2004, the OCC approved a revised schedule. In October 2004, PSO filed supplemental information requesting consideration of approximately $55 million of additional annual operations and maintenance expenses and annual capital costs to enhance system reliability. In November 2004, PSO filed a plan with the OCC seeking interim rate relief to fund a portion of the costs to meet the new state service quality and reliability requirements pending the outcome of the current case. In the filing, PSO sought interim approval to collect annual incremental distribution tree trimming costs of approximately $23 million from its customers. Intervenors and the OCC Staff filed testimony recommending that the interim rate relief requested by PSO be modified or denied. The OCC issued an order on PSO's interim request in January 2005, which allows PSO to recover up to an additional $12 million annually for reliability activities beginning in December 2004. Expenses exceeding that amount and the amount currently included in base rates will be considered in the base rate case.

The OCC Staff and intervenors filed testimony regarding their recommendations on revenue requirement, fuel procurement, resource planning and vegetation management in January 2005. Their recommendations ranged from a decrease in annual existing rates between $15 million and $36 million. In addition, one party recommended that the OCC require PSO file additional information regarding its natural gas purchasing practices. In the absence of such a filing, this party suggested that $30 million of PSO's natural gas costs not be recovered from customers because it failed to implement a procurement strategy that, according to this party, would have resulted in lower natural gas costs. OCC Staff and intervenors recommended a return on common equity ranging from 9.3% to 10.11%. PSO's rebuttal testimony was filed in February 2005, and that testimony reflects a number of adjustments to PSO's June 2004 updated filing. These adjustments result in a decrease of PSO's revenue deficiency from $41 million to $28 million, although approximately $9 million of that decrease are items that would be recovered through the fuel adjustment clause rather than through base rates. Hearings are scheduled to begin in March 2005, and a final decision is not expected any earlier than the second quarter of 2005. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

FERC Order on Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the Midwest Independent System Operator (MISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and expanded PJM regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners including AEP East companies under the RTOs' revenue distribution protocols.

In November 2003, the FERC issued an order finding that the T&O rates of the former Alliance RTO participants, including AEP, should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and former Alliance RTO participants to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004. The FERC was expected to implement a new rate design after the two-year period. In April 2004, the FERC approved a settlement that delayed elimination of T&O rates and the implementation of SECA replacement rates until December 1, 2004 when the FERC would implement a new rate design.

On November 18, 2004, the FERC conditionally approved a license plate rate design to eliminate rate pancaking for transmission service within the Combined Footprint and adopted its previously approved SECA transition rate methodology to mitigate the effects of the elimination of T&O rates effective December 1, 2004. Under license plate rates, customers serving load within a RTO pay transmission service rates based on the embedded cost of the transmission facilities in the local pricing zone where the load being served is located. The use of license plate rates would shift costs that we previously recovered from our T&O service customers to mainly AEP's native load customers within the AEP East pricing zone. The SECA transition rates will remain in effect through March 31, 2006. The SECA rates are designed to mitigate the loss of revenues due to the elimination of T&O rates.

The SECA rates became effective December 1, 2004. Billing statements from PJM for December 2004 did not reflect any credits to AEP for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP accrued $11 million in December 2004 for SECA revenues. On January 7, 2005, AEP and Exelon filed joint comments and protest with the FERC including a request that FERC direct PJM and MISO to comply with the FERC decision and collect all SECA revenues due with interest charges for all late-billed amounts. On February 10, 2005, the FERC issued an order indicating that the SECA transition rates would be subject to refund or surcharge and set for hearing all remaining aspects of the compliance filings to the November 18 order, including our request that the FERC direct PJM and MISO begin billing and collecting the SECA transition rates.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA charges was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, or if any increase in the AEP East Companies' transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Pension and Postretirement Benefit Plans

We maintain qualified, defined benefit pension plans (Qualified Plans or Pension Plans), which cover a substantial majority of nonunion and certain union employees, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, we have entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees in the U.S. (Postretirement Plans). The Qualified Plans and Postretirement Plans are collectively "the Plans."

The following table shows the net periodic cost (credit) for our Pension Plans and Postretirement Plans:

	2004	2003
	(in millions)	
Net Periodic Cost (Credit):		
Pension Plans	$ 40	$ (3)
Postretirement Plans	141	188
Assumed Rate of Return:		
Pension Plans	8.75%	9.00%
Postretirement Plans	8.35%	8.75%

The net periodic cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plans' assets. In developing the expected long-term rate of return assumption, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. We also considered historical returns of the investment markets as well as our 10-year average return, for the period ended December 2004, of approximately 12%. We anticipate that the investment managers we employ for the Plans will continue to generate long-term returns averaging 8.75%.

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:

	2004 Actual Pension Plan Asset Allocation	2004 Actual Postretirement Plan Asset Allocation	2005 Target Asset Allocation	Assumed/Expected Long-term Rate of Return
Equity	68%	70%	70%	10.50%
Fixed Income	25%	28%	28%	5.00%
Cash and Cash Equivalents	7%	2%	2%	2.00%
Total	100%	100%	100%	
Overall Expected Return (weighted average)				8.75%

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. Because of a $200 million discretionary contribution to the Qualified Plans at the end of 2004, the actual asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced back to the target allocation in January 2005. We believe that 8.75% is a reasonable long-term rate of return on the Plans' assets despite the recent market volatility. The Plans' assets had an actual gain of 13.75% and 23.80% for the twelve months ended December 31, 2004 and 2003, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them 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, 2004, we had cumulative losses of approximately $30 million which 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 SFAS No. 87, "Employers' Accounting for Pensions."

The method used to determine the discount rate that we utilize for determining future obligations was revised in 2004. Historically, we based it on the Moody's AA bond index which includes long-term bonds that receive one of the two highest ratings from a recognized rating agency. The discount rate determined on this basis was 6.25% at December 31, 2003 and would have been 5.75% at December 31, 2004. In 2004, we changed to 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 was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2004 under this method was 5.50% for the Pension Plans and 5.80% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Plans' assets of 8.75%, a discount rate of 5.50% and various other assumptions, we estimate that the pension cost for all pension plans will approximate $55 million, $54 million and $61 million in 2005, 2006 and 2007, respectively. We estimate Postretirement Plan cost will approximate $164 million, $155 million and $146 million in 2005, 2006 and 2007, respectively. Future actual cost 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 0.5% basis point change to selective actuarial assumptions are in "Pension and Other Postretirement Benefits" within the "Critical Accounting Estimates" section of this Management's Financial Discussion and Analysis of Results of Operations.

The value of our Pension Plans' assets increased to $3.6 billion at December 31, 2004 from $3.2 billion at December 31, 2003. The Qualified Plans paid $265 million in benefits to plan participants during 2004 (nonqualified plans paid $8 million in benefits). The value of our Postretirement Plans' assets increased to $1.1 billion at December 31, 2004 from $1.0 billion at December 31, 2003. The Postretirement Plans paid $109 million in benefits to plan participants during 2004.

For our underfunded pension plans, the accumulated benefit obligation in excess of plan assets was $474 million and $445 million at December 31, 2004 and 2003, respectively.

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2004 and 2003, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2004	2003
	(in millions)	
Other Comprehensive Income	$ (92)	$ (154)
Deferred Income Taxes	(52)	(75)
Intangible Asset	(3)	(5)
Other	(10)	13
Minimum Pension Liability	$ (157)	$ (221)

We made an additional discretionary contribution of $200 million in the fourth quarter of 2004 and intend to make additional discretionary contributions of $100 million per quarter in 2005 to meet our goal of fully funding all qualified pension plans by the end of 2005.

Certain pension plans we sponsor and maintain contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act of 1967, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. We believe that the defined benefit pension plans we sponsor and maintain are in compliance with the applicable requirements of such laws.

Litigation

Federal EPA Complaint and Notice of Violation

See discussion of the Federal EPA Complaint and Notice of Violation within "Significant Factors – Environmental Matters."

Enron Bankruptcy

In 2002, certain of our subsidiaries filed claims against Enron and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain of our subsidiaries had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy.

Enron Bankruptcy – Bammel storage facility and HPL indemnification matters – In connection with the 2001 acquisition of HPL, we entered into a prepaid arrangement under which we acquired exclusive rights to use and operate the underground Bammel gas storage facility and appurtenant pipelines pursuant to an agreement with BAM Lease Company. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years.

In January 2004, we filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron did not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In April 2004, AEP and Enron entered into a settlement agreement under which we acquired title to the Bammel gas storage facility and related pipeline and compressor assets, plus 10.5 billion cubic feet (BCF) of natural gas currently used as cushion gas for $115 million, which increased our investment in HPL. AEP and Enron agreed to release each other from all claims associated with the Bammel facility, including our indemnity claims. The settlement received Bankruptcy Court approval on September 30, 2004 and closed in November 2004. The parties' respective trading claims and Bank of America's (BOA) purported lien on approximately 55 BCF of natural gas in the Bammel storage reservoir (as described below) are not covered by the settlement agreement.

Enron Bankruptcy – Right to use of cushion gas agreements – In connection with the 2001 acquisition of HPL, we also entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 BCF of cushion gas (including the 10.5 BCF described in the preceding paragraph) 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 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in state court in Texas seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOA's claims.

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA's Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA has objected to the Magistrate Judge's decision and the matter is now before the District Judge.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements.

On January 26, 2005, we sold a 98% limited partner interest in HPL. We have indemnified the buyer of our 98% interest in HPL against any damages resulting from the BOA litigation. The determination of the amount of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the BOA dispute.

Enron Bankruptcy – Commodity trading settlement disputes – In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. AEP has asserted its right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. The parties are currently in nonbinding court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. The parties are currently in nonbinding court-sponsored mediation.

Enron Bankruptcy – Summary – The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and there is a dispute regarding the cushion gas agreement. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows or financial condition.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In January 2005, a hearing was held before an ALJ. We expect an initial decision from the ALJ later this year. The SEC will review the initial decision.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals with us and claimed that we owed approximately $34 million. In April 2003, we filed a lawsuit against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately $68 million. We are claiming that BOM owes us at least $45 million related to previously recorded receivables on which we hold approximately $20 million of credit collateral. We have reserved $4 million against these receivables to reflect the risks of loss, based on the low end of a range of valuations calculated for purposes of the litigation and related mediation. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Coal Transportation Dispute

Certain of our subsidiaries, as joint owners of a generating station have disputed transportation costs billed for coal received between July 2000 and the present time. Our subsidiaries have remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, our subsidiaries recorded a provision for possible loss in December 2004. Of the total provision, a share for deregulated subsidiaries affected income in 2004, a share was recorded as a receivable due to partial ownership of the plant by third parties and the remainder was deferred under the operation of a deferred fuel mechanism. Management continues to work toward mitigating the disputed amounts to the extent possible.

Energy Market Investigations

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and continued to respond to supplemental data requests from some of these agencies in 2003 and 2004.

In September 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleged that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC sought civil penalties, restitution and disgorgement of benefits. We responded to the complaint in September 2004. In January 2005, we reached settlement agreements totaling $81 million with the CFTC, the U.S. Department of Justice and the FERC regarding investigations of past gas price reporting and gas storage activities, these being all agencies known still to be investigating these matters as to AEP. Our settlements do not admit nor should they be construed as an admission of violation of any applicable regulation or law. We made the settlement payments to the agencies in the first quarter of 2005 in accordance with the respective contractual terms. The agencies have ended their investigations and the CFTC litigation filed in September 2003 has also ended. During 2003 and 2004, we provided for the settlement payments in the amounts of $45 million and $36 million (nondeductible for federal income tax purposes), respectively. We do not expect any impact on 2005 results of operations as a result of these investigations and settlements.

Shareholders' Litigation

In 2002, lawsuits alleging securities law violations, a breach of fiduciary duty for failure to establish and maintain adequate internal controls and violations of the Employee Retirement Income Security Act (ERISA) were filed against us, certain executives, members of the Board of Directors and certain investment banking firms. All of these actions except the ERISA claims were dismissed during 2004. We intend to defend vigorously against the remaining ERISA actions. See Note 7 for further discussion.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County, California Superior Court against forty energy companies, including AEP, and two publishing companies 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 has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. Since then, a number of cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Management is unable to predict the outcome of these lawsuits but intends to defend vigorously against the claims made in each case where an AEP company is a defendant.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against eighteen companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. In December 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. We and the other defendants filed a motion to dismiss the complaint which the Court denied in September 2004. We intend to defend vigorously against these claims.

TEM Litigation

See discussion of TEM litigation within the "Financial Condition – Other" section of this Management's Financial Discussion and Analysis.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit against us and four of our subsidiaries, certain nonaffiliated energy companies and ERCOT alleging violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against the AEP companies. TCE has appealed the trial court's decision to the United States Court of Appeals for the Fifth Circuit. See Note 7 for further discussion.

Other Litigation

We are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on results of operations, cash flows or financial condition.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Environmental Matters

There are new environmental control requirements that we expect will result in substantial capital investments and operational costs. The sources of these future requirements include:

- Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,
- New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
- Possible future requirements to reduce carbon dioxide emissions to address concerns about global climate change.

In addition to achieving full compliance with all applicable legal requirements, we strive to go beyond compliance in an effort to be good environmental stewards. For example, we invest in research, through groups like the Electric Power Research Institute, to develop, implement and demonstrate new emission control technologies. We plan to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices. We have a proven record of efficiently producing and delivering electricity while minimizing the impact on the environment. We invested over $2 billion, from 1990 through 2004, to equip many of our facilities with pollution control technologies. We will continue to make investments to improve the air emissions from our fossil fuel generating stations as this is the most cost-effective generation source to meet our customers' electricity needs.

In 2002, we joined the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program. We committed to reduce or offset approximately 18 million short tons of CO_2 emissions during 2003-2006 below our baseline emissions (i.e. average emission levels during 1998-2001) as adjusted to reflect any changes in our baseline during the commitment period. During 2003, we reduced or offset our emissions by approximately seven million tons below our voluntary emissions cap and, based on preliminary estimates, we anticipate being below our voluntary emissions cap in 2004.

In August 2004, we released "An Assessment of AEP's Actions to Mitigate the Economic Impacts of Emissions Policies." The assessment evaluated our operating emissions control technology, planned investment in additional control equipment and risks associated with an uncertain regulatory environment. It concluded that our actions over the past decade constitute a solid foundation for future efforts to address the intersection between environmental policy and business opportunities. It also concluded that irrespective of the uncertainties surrounding potential air emission regulations and possible future mandatory greenhouse gas regulations, the pollution control investments planned over the next six to eight years are sound. The report also details many of the voluntary actions we are undertaking to limit our greenhouse gas emissions and to develop and/or advance future clean energy technologies.

The Current Air Quality Regulatory Framework

The CAA establishes the federal regulatory authority and oversight for emissions from our fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

National Ambient Air Quality Standards: The Federal EPA periodically reviews the available scientific data for six pollutants and establishes a standard for concentration levels in ambient air for these substances to protect the public welfare and public health with an extra margin for safety. These requirements are known as "national ambient air quality standards" (NAAQS).

The states identify those areas within their state that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). States must develop their individual state implementation plans (SIPs) with the intention of bringing nonattainment areas into compliance with the NAAQS. In developing a SIP, each state must demonstrate that attainment areas will maintain compliance with the NAAQS. This is accomplished by controlling sources that emit one or more pollutants or precursors to those pollutants. The Federal EPA approves SIPs if they meet the minimum criteria in the CAA. Alternatively, the Federal EPA may prescribe a federal implementation plan if they conclude that a SIP is deficient. Additionally, the Federal EPA can impose sanctions, up to and including withholding of federal highway funds, in states that fail to submit an adequate SIP or a SIP that fails to bring nonattainment areas into NAAQS compliance within the time prescribed by the CAA.

The CAA also establishes visibility goals, which are known as the regional haze program, for certain federally designated areas, including national parks. States are required to develop and submit SIP provisions that will demonstrate reasonable progress toward preventing the impairment and remedying any existing impairment of visibility in these federally designated areas.

Each state's SIP must include requirements to control sources that emit pollutants in that state as well as requirements to control sources that significantly contribute to nonattainment areas in another state. If a state believes that its air quality is impacted by upwind sources outside their borders, that state can submit a petition that asks the Federal EPA to impose control requirements on specific sources in other states if those states' SIPs do not contain adequate requirements to control those sources. For example, the Federal EPA issued a NO_x Rule in 1997, which affected 22 eastern states (including states in which AEP operates) and the District of Columbia. The NO_x Rule asked these 23 jurisdictions to adopt requirements for utility and industrial boilers and certain other emission sources to employ cost-effective control technologies to reduce NO_x emissions. The purpose of the request was to reduce the contribution from these 23 jurisdictions to ozone nonattainment areas in certain eastern states.

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which we operate that were subject to the NO_x Rule have submitted the required SIP revisions. In response, the Federal EPA approved the SIPs. The compliance date for the SIPs implementing the NO_x Rule and the revised Section 126 Rule was May 31, 2004. These requirements apply to most of our coal-fired generating units.

In 2000, the Texas Commission on Environmental Quality (TCEQ) adopted rules requiring significant reductions in NO_x emissions from utility sources, including TCC and SWEPCo. The compliance requirements began in May 2003 for TCC and will begin in May 2005 for SWEPCo.

We installed a variety of emission control technologies to reduce NO_x emissions and to comply with applicable state and federal NO_x requirements. These include selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units.

Our electric generating units are currently subject to other SIP requirements that control SO_2 and particulate matter emissions in all states, and that control NO_x emissions in certain states. Management believes that our generating plants comply with applicable SIP limits for SO_2, NO_x and particulate matter.

Hazardous Air Pollutants: In the 1990 Amendments to the CAA, Congress required the Federal EPA to identify the sources of 188 hazardous air pollutants (HAPs) and to develop regulations that prescribe a level of HAP emission reduction. These reductions must reflect the application of maximum achievable control technology (MACT). Congress also directed the Federal EPA to investigate HAP emissions from the electric utility sector and to submit a report to Congress. The Federal EPA's 1998 report to Congress identified mercury emissions from coal-fired electric utility units and nickel emissions from oil-fired utility units as sources of HAP emissions that warranted further investigation and possible control.

New Source Performance Standards and New Source Review: The Federal EPA establishes New Source Performance Standards (NSPS) for 28 categories of major stationary emission sources that reflect the best demonstrated level of pollution control. Sources that are constructed or modified after the effective date of an NSPS standard are required to meet those limitations. For example, many electric generating units are regulated under the NSPS for SO_2, NO_x, and particulate matter. Similarly, each SIP must include regulations that require new sources, and major modifications at existing emission sources that result in a significant net increase in emissions, to submit a permit application and undergo a review of available technologies to control emissions of pollutants. These rules are called new source review (NSR) requirements.

Different NSR requirements apply in attainment and nonattainment areas.

In attainment areas:

- An air quality review must be performed, and
- The best available control technology must be employed to reduce new emissions.

In nonattainment areas,

- Requirements reflecting the lowest achievable emission rate are applied to new or modified sources, and
- All new emissions must be offset by reductions in emissions of the same pollutant from other sources within the same control area.

Neither the NSPS nor NSR requirements apply to certain activities, including routine maintenance, repair or replacement, changes in fuels or raw materials that a source is capable of accommodating, the installation of a pollution control project, and other specifically excluded activities.

Title IV of the CAA (Acid Rain)

The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO_2 emitted from electric generating units by approximately 50 percent from the 1980 levels. This program also established a nationwide cap on utility SO_2 emissions of 8.9 million tons per year. The Federal EPA administers the SO_2 program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each generating unit surrenders one allowance for each ton of SO_2 that it emits. Emission sources may bank their excess allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NO_x emissions through the use of available combustion controls. Generating units must meet their specific NO_x emission standards or units under common control may participate in an annual averaging program for that group of units.

Future Reduction Requirements for SO_2, NO_x, and Mercury

In 1997, the Federal EPA adopted more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA finalized designations for fine particulate matter nonattainment areas on December 17, 2004. Approximately 200 counties are included in the nonattainment areas including many rural counties in the Eastern United States where our generating units are located. The Federal EPA has not yet issued a rule establishing planning and control requirements or attainment deadlines for these areas. The Federal EPA finalized designations for ozone nonattainment areas on April 15, 2004. On the same day, the Administrator of the Federal EPA signed a final rule establishing the elements that must be included in SIPs to achieve the new standards, and setting deadlines ranging from 2008 to 2015 for achieving compliance with the final standard, based on the severity of nonattainment. All or parts of 474 counties are affected by this new rule, including many urban areas in the Eastern United States.

The Federal EPA has identified SO_2 and NO_x emissions as precursors to the formation of fine particulate matter. NO_x emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NO_x and SO_2 from our generating units are highly probable. In addition, the Federal EPA proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation is supported by the Bush Administration. This legislation would regulate NO_x, SO_2, and mercury emissions from electric generating plants. We support enactment of a comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. We believe this legislation would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. We believe regulation or legislation will require us to substantially reduce SO_2, NO_x and mercury emissions over the next ten years.

Regulatory Emissions Reductions

In January 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO_2, NO_x and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed a Clean Air Interstate Rule (CAIR) to reduce SO_2 and NO_x emissions across the eastern half of the United States (29 states and the District of Columbia) and make progress toward attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The CAIR would require affected states to include, in their SIPs, a program to reduce NO_x and SO_2 emissions from coal-fired electric utility units. SO_2 and NO_x emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO_2 emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NO_x emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO_2 and NO_x trading programs were proposed in June 2004.

On April 15, 2004, the Federal EPA Administrator signed a proposed rule detailing how states should analyze and include "Best Available Retrofit" requirements for individual facilities in their SIPs to address regional haze. The guidance applies to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain regulated pollutants in specific industrial categories, including utility boilers. The Federal EPA included an alternative "Best Available Retrofit" program based on emissions budgeting and trading programs. For generating units that are affected by the CAIR, described above, the Federal EPA proposed that participation in the trading program under the CAIR would satisfy any applicable "Best Available Retrofit" requirements. However, the guidance preserves the ability of a state to require site-specific installation of pollution control equipment through the SIP for purposes of abating regional haze.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of MACT on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain generating units have achieved comparable levels of mercury reduction by installing conventional SO_2 (scrubbers) and NO_x (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite. The proposed standards for sub-bituminous coals potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and we support, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO_2 and NO_x reduction requirements imposed on the same sources under the CAIR. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, which can be used to comply with the more stringent SO_2 and NO_x

requirements, have also proven effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018. A supplemental proposal including unit-specific allocations and a framework for the emissions budgeting and trading program preferred by the Federal EPA was published in the Federal Register in March 2004. We filed comments on both the initial proposal and the supplemental proposal in June 2004.

The Federal EPA's proposals are the beginning of a lengthy rulemaking process, which will involve supplemental proposals on many details of the new regulatory programs, written comments and public hearings, issuance of final rules, and potential litigation. In addition, states have substantial discretion in developing their rules to implement cap-and-trade programs, and will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here.

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that we will invest in additional conventional pollution control technology on a major portion of our fleet of coal-fired power plants. Finalization of new requirements for further SO_2, NO_x and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control. The cost of such facilities could have an adverse effect on future results of operations, cash flows and financial condition unless recovered from customers.

Estimated Air Quality Environmental Investments

Each of the current and possible future environmental compliance requirements discussed above will require us to make significant additional investments, some of which are estimable. The proposed rules discussed above have not been adopted, will be subject to further revision, and may be the subject of a court challenge and further modifications.

All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including:

- Timing of implementation
- Required levels of reductions
- Allocation requirements of the new rules, and
- Our selected compliance alternatives.

As a result, we cannot estimate our compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

All of the costs discussed below are incremental to our current investment base and operating cost structure. We intend to seek recovery of these expenditures for pollution control technologies, replacement generation and associated operating 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, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Estimated Investments for NO_x Compliance

We estimate that we will make future investments of approximately $450 million to comply with the Federal EPA's NO_x Rule, the TCEQ Rule and other final NO_x-related requirements. Approximately $380 million of these investments are expected to be expended during 2005–2007. As of December 31, 2004, we have invested approximately $1.3 billion to comply with various NO_x requirements.

Estimated Investments for SO_2 Compliance

We are complying with Title IV SO_2 requirements by installing scrubbers, other controls and fuel switching at certain generating units. We also use SO_2 allowances that we:

- Received in the Federal EPA's annual allowance allocation,
- Obtained through participation in the annual Federal allowance auction,
- Purchased in the market, and
- Obtained as bonus allowances for installing controls early.

Decreasing SO_2 allowance allocations, our diminishing SO_2 allowance bank, and increasing allowance prices in the market will require us to install additional controls on certain of our generating units. We plan to install 3,500 MW of additional scrubbers to comply with our Title IV SO_2 obligations. We invested approximately $97 million during 2004. In total, we estimate these additional capital costs to be approximately $1.2 billion, the remainder of which will be expended during 2005–2007.

Estimated Investments to Comply with Future Reduction Requirements

Our planning assumptions for the levels and timing of emissions reductions parallel the reduction levels and implementation time periods stated in the proposed rules issued by the Federal EPA in January 2004. We have also assumed that the Federal EPA will implement a mercury trading option and will design its proposed cap and trade mechanism for SO_2, NO_x and mercury emissions in a manner similar to existing cap and trade programs. Based on these assumptions, compliance would require additional capital investment of approximately $1.7 billion by 2010, the end of the first phase for each proposed rule. We estimate that we will invest $1 billion of the capital amount through 2007. We also estimate that we would incur accumulated increases in variable operation and maintenance expenses of $150 million for the periods through 2010, due to the costs associated with the maintenance of additional control systems, disposal of scrubber by-products and the purchase of reagents.

If the Federal EPA's preferred mercury trading option is not implemented, then any alternative mercury control program requiring adherence to MACT standards would have higher implementation costs that could be significant. We cannot currently estimate the nature or amount of these costs. Furthermore, scrubber and SCR technologies could not be deployed at every bituminous-fired plant that we operate within the three-year compliance schedule provided under the proposed MACT rule. These MACT compliance costs, which we are not able to estimate, would be incremental to other cost estimates that we have discussed above.

Between 2010 and 2020, we expect to incur additional costs for pollution control technology retrofits and investment of $1.6 billion. However, the post-2010 capital investment estimates are quite uncertain, reflecting the uncertain nature of future air emission regulatory requirements, technology performance and costs, new pollution control and generating technology developments, among other factors. Associated operation and maintenance expenses for the equipment will also increase during those years. We cannot estimate these additional costs because of the uncertainties associated with the final control requirements and our associated compliance strategy, but these additional costs are expected to be significant.

New Source Review Litigation

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

The Federal EPA and a number of states have alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period.

On June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to "perfect" its complaint in the pending litigation. The NOV expands the number of alleged "modifications" undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA filed a motion to amend its complaints and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, eight Northeastern States filed a separate complaint containing the same allegations against the Conesville and Amos plants that the judge disallowed in the pending case. We filed an answer to the complaint in January 2005.

We are unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered from customers.

In September 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio SIP occurred at the Stuart Station, and seeking injunctive relief and civil penalties. Stuart Station is jointly-owned by CSPCo (26%) and two nonaffiliated utilities. The owners have filed a motion to dismiss portions of the complaint. We believe the allegations in the complaint are without merit, and intend to defend vigorously against this action. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions.

On July 19, 2004, the TCEQ issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On August 30, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the reporting of volatile organic compound emissions at the Pirkey Plant, but after investigation determined that further enforcement was not warranted and withdrew the notice on January 5, 2005.

SWEPCo has previously reported to the TCEQ, deviations related to the receipt of off-specification fuel at Knox Lee, the volatile organic compound emissions at Pirkey, and the referenced recordkeeping and reporting requirements and heat input value at Welsh. We have submitted additional responses to the Notice of Enforcement and the notice from the special interest groups. Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

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 disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and nonhazardous materials. We are currently incurring costs to safely dispose of these substances.
Superfund addresses clean-up of hazardous substances at disposal sites and authorized the Federal EPA to administer the clean-up programs. At year-end 2004, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for four sites. There are six 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 seven sites under state law. Liability has been resolved for a number of sites with no significant effect on results of operations. 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. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding our potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, our present estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. If significant cleanup costs were attributed to our subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in our electricity prices.

Emergency Release Reporting

Superfund also requires immediate reporting to the Federal EPA for releases of hazardous substances to the environment above the identified reportable quantity (RQ). The Environmental Planning and Community Right-to-Know Act (EPCRA) requires immediate reporting of releases of hazardous substances which cross property boundaries of the releasing facility.

On July 27, 2004, the Federal EPA Region 5 issued an Administrative Complaint related to alleged failure of I&M to immediately report under Superfund and EPCRA a November 2002 release of sodium hypochlorite from the Cook Plant. The Federal EPA's Complaint seeks an immaterial amount of civil penalties. I&M has requested a hearing and raised several defenses to the claim, including federally permitted release exemption from reporting. Negotiations on the penalty amount are continuing.

On December 21, 2004, the Federal EPA notified OPCo of its intent to file a Civil Administrative Complaint, alleging one violation of Superfund reporting obligations and two violations of EPCRA for failure to timely report a June 2004 release of an RQ amount of ammonia from OPCo's Gavin Plant SCR system. The Federal EPA indicated its intent to seek civil penalties. In February 2005, OPCo provided relevant information that the Federal EPA should consider in advance of any filing.

Global Climate Change

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly carbon dioxide (CO_2), which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not submitted to the Senate for its advice and consent. In March 2001, President Bush announced his opposition to the treaty. Ratification of the treaty by a majority of the countries' legislative bodies is required for it to be enforceable. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries and is now in effect as of February 2005.

In August 2003, the Federal EPA issued a decision in response to a petition for rulemaking seeking reductions of CO_2 and other greenhouse gas emissions from mobile sources. The Federal EPA denied the petition and issued a memorandum stating that it does not have the authority under the CAA to regulate CO_2 or other greenhouse gas emissions that may affect global warming trends. The Circuit Court of Appeals for the District of Columbia is reviewing these actions.

We have been working with the Bush Administration on a voluntary program aimed at meeting the President's goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, we have been a leader in pursuing voluntary actions to control greenhouse gas emissions. We expanded our commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program. We made a voluntary commitment to reduce or offset a total of 18 million tons of CO_2 emissions during 2003-2006 as adjusted to reflect any changes in our baseline during the commitment period.

Carbon Dioxide Public Nuisance Claims

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of three special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. Management believes the actions are without merit and intends to defend vigorously against the claims.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law I&M and TCC participate in the DOE's SNF disposal program which is described in the "SNF Disposal" section of Note 7. Since 1983, I&M has collected $333 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. We deposited $118 million of these funds in external trust funds to provide for the future disposal of SNF and remitted $215 million to the DOE. TCC has collected and remitted to the DOE, $61 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date, DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of TCC and the other STP owners, along with a number of nonaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other nonaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. In January 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continued on the issue of damages owed to I&M by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against I&M and denied damages. In July 2004, I&M appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. As long as the delay in the availability of a government-approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2003 estimate the cost to decommission the Cook Plant ranges from $889 million to $1.1 billion in 2003 nondiscounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2004, the total decommissioning trust fund balance for Cook Plant was $791 million, which includes earnings on the trust investments. In May 2004, an updated decommissioning study was completed for STP. The study estimates TCC's share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2004, the total decommissioning trust fund for TCC's share of STP was $143 million, which includes earnings on the trust investments. TCC is in the process of selling its ownership interest in STP to two nonaffiliated companies, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP. Estimates from the decommissioning studies could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. I&M and TCC will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, our future results of operations, 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.

Clean Water Act Regulation

On July 9, 2004, the Federal EPA published in the Federal Register a rule pursuant to the Clean Water Act that will require all large existing, once-through cooled power plants to meet certain performance standards to reduce the mortality of juvenile and adult fish or other larger organisms pinned against a plant's cooling water intake screen. All plants must reduce fish mortality by 80% to 95%. A subset of these plants that are located on sensitive water bodies will be required to meet additional performance standards for reducing the number of smaller organisms passing through the water screens and the cooling system. These plants must reduce the rate of smaller organisms passing through the plant by 60% to 90%. Sensitive water bodies are defined as oceans, estuaries, the Great Lakes, and small rivers with large generating plants. These rules will result in additional capital and operation and maintenance expenses to ensure compliance. The estimated capital cost of compliance for our facilities, based on the Federal EPA's analysis in the rule, is $193 million. Any capital costs associated with compliance activities to meet the new performance standards would likely be incurred during the years 2008 through 2010. We have not independently confirmed the accuracy of the Federal EPA's estimate. The rule has provisions to limit compliance costs. We may propose less costly site-specific performance criteria if our compliance cost estimates are significantly greater than the Federal EPA's estimates or greater than the environmental benefits. The rule also allows us to propose mitigation (also called restoration measures) that is less costly and has equivalent or superior environmental benefits than meeting the criteria in whole or in part. Several states, electric utilities (including our APCo subsidiary) and environmental groups appealed certain aspects of the rule. We cannot predict the outcome of the appeals.

Other Environmental Concerns

We perform environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, we are managing other environmental concerns which we do not believe are material or potentially material at this time. If they become significant or if any new matters arise that we believe could be material, they could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers 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 results of operations or financial condition.

Management has discussed the development and selection of its critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee has reviewed the disclosure relating to them.

Management believes 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 under different assumptions and conditions.

The sections that follow present information about AEP's most 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 passage to our customers through regulated revenues in the same accounting period.

We also record regulatory liabilities for refunds, or probable refunds, to customers that have not yet been made.

Assumptions and Approach Used - When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, 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, the rate of return earned on invested capital and the timing and amount of assets to be recovered through regulated rates. If it is determined that 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 results of operations. Refer to Note 5 of the Notes to Consolidated Financial Statements for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required – We recognize and 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 is performed 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 also estimated. This estimate is reversed in the following month and actual revenue is recorded based on meter readings.

Unbilled revenues included in Revenue were $22 million, $13 million and $7 million, respectively for the years ended December 31, 2004, 2003 and 2002.

Assumptions and Approach Used – The monthly estimate for unbilled revenues is calculated by operating company as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to the occurrence of problems in meter readings, meter drift and other anomalies, a separate monthly calculation determines factors that limit 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 dividing the current month aggregated result by the billed KWH. The limits are then 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.

In addition, an annual comparison to a load research estimate is performed for the East Companies. The annual load research study is an independent unbilled KWH estimate based on a sample of accounts. The unbilled estimate is also adjusted annually for significant differences from the load research estimate.

Effect if Different Assumptions Used – Significant fluctuations in energy demand for the unbilled period, weather impact, 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%.

<u>Revenue Recognition – Accounting for Derivative Instruments</u>

Nature of Estimates Required – Management considers 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 is somewhat subjective in nature and involves 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. Liquidity adjustments are calculated by utilizing future bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments are based on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings.

We evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided for in the original documentation related to hedge accounting.

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 are ultimately settled.

The probability that hedged forecasted transactions will 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 in operating income.

For additional information regarding accounting for derivative instruments, see sections labeled Credit Risk and VaR Associated with Risk Management Contracts within "Quantitative and Qualitative Disclosures About Risk Management Activities."

Long-Lived Assets

Nature of Estimates Required – In accordance with the requirements of SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," long-lived assets are evaluated periodically 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 under SFAS 144. These events or circumstances may include the expected ability to recover additional investment in environmental compliance expenditures, the relative pricing of wholesale electricity by region, the anticipated demand and the cost of fuel. If the carrying amount is not recoverable, an impairment is recorded to the extent that the fair value of the asset 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 was probable. For nonregulated assets, an impairment charge would be recorded as a charge against earnings.

Assumptions and Approach Use - 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, 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, fair value is estimated 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. 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 periodic evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. In cases of impairment as described in Note 10, we made our best estimate of fair value using valuation methods based on the most current information at that time. We have been in the process of divesting certain noncore assets and their sales values can vary from the recorded fair value as described in Note 10. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

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 SFAS 87, "Employers' Accounting For Pensions" and SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions", respectively. See Note 11 of the Notes to Consolidated Financial Statements for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of our pension and postretirement obligations, costs and liabilities is dependent on a variety of assumptions used by our actuaries and us. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded.

Assumptions and Approach Used - The critical assumptions used in developing the required estimates include the following key factors:

- discount rate
- expected return on plan assets
- health care cost trend rates
- rate of compensation increases

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 or longer or shorter life spans of participants. 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 Benefits Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2004 Benefit Obligations:				
Discount Rate	$ (175)	$ 182	$ (133)	$ 142
Salary Scale	11	(11)	4	(4)
Cash Balance Crediting Rate	(20)	20	N/A	N/A
Health Care Trend Rate	N/A	N/A	129	(121)
Expected Return on Assets	N/A	N/A	N/A	N/A
Effect on 2004 Periodic Cost:				
Discount Rate	-	1	(11)	11
Salary Scale	2	(2)	1	(1)
Cash Balance Crediting Rate	3	(3)	N/A	N/A
Health Care Trend Rate	N/A	N/A	19	(18)
Expected Return on Assets	(17)	17	(5)	5

New Accounting Pronouncements

We implemented FASB Staff Position (FSP) FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," effective April 1, 2004, retroactive to January 1, 2004. Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106's 10 percent corridor.

In December 2004, the FASB issued SFAS 123R, "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. We will implement SFAS 123R in the third quarter of 2005 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. A cumulative effect of a change in accounting principle is recorded for the effect of initially applying the statement. We do not expect implementation of SFAS 123R to materially affect our results of operations, cash flows or financial condition.

We implemented FIN 46R, "Consolidated of Variable Interest Entities," effective March 31, 2004 with no material impact to our financial statements. FIN 46R is a revision to FIN 46 which interprets the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties.

Other Matters

Seasonality

The sale of electric power in our service territories is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of our facilities and the terms when we enter into power contracts. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and may impact cash flows and financial condition.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances, we have certain market risks inherent in our business activities. These risks include commodity price risk, interest rate risk, foreign exchange risk and credit risk. They represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

We have established policies and procedures which allow us to identify, assess, and manage market risk exposures in our day-to-day operations. Our risk policies have been reviewed with our Board of Directors and approved by our Risk Executive Committee. Our Chief Risk Officer administers our risk policies and procedures. The Risk Executive Committee establishes risk limits, approves risk policies, and assigns responsibilities regarding the oversight and management of risk and monitors risk levels. Members of this committee receive daily, weekly, and monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, Credit Risk Management, Market Risk Oversight, and senior financial and operating managers.

We actively participate in the Committee of Chief Risk Officers (CCRO) to develop standard disclosures for risk management activities around risk management contracts. The CCRO is composed of the chief risk officers of major electricity and gas companies in the United States. The CCRO adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. Implementation of the disclosures is voluntary. We support the work of the CCRO and have embraced the disclosure standards. The following tables provide information on our risk management activities:

Mark-to-Market Risk Management Contract Net Assets (Liabilities)

This table provides detail on changes in our mark-to-market (MTM) net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2004
(in millions)

	Utility Operations	Investments-Gas Operations	Investments-UK Operations (h)	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2003	$ 286	$ 5	$ (246)	$ 45
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(116)	(24)	246	106
Fair Value of New Contracts When Entered During the Period (b)	11	-	-	11
Net Option Premiums Paid/(Received) (c)	(3)	(1)	-	(4)
Change in Fair Value Due to Valuation Methodology Changes (d)	3	-	-	3
Changes in Fair Value of Risk Management Contracts (e)	74	20	(12)	82
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	22	-	-	22
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2004	$ 277	$ -	$ (12)	265
Net Cash Flow and Fair Value Hedge Contracts (g)				5
Ending Net Risk Management Assets at December 31, 2004				$ 270

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) The "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts entered in 2004.

(d) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

(g) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed in detail within the following pages.

(h) During 2004, we began to unwind our risk management contracts within the U.K. as part of our planned divestiture of our UK Operations. We completed the sale of substantially all of our operations and assets in the Investments-UK Operations segment in July 2004 and we expect the remaining MTM Risk Management Current Net Liabilities to be finalized in the first quarter of 2005.

Detail on MTM Risk Management Contract Net Assets (Liabilities)
As of December 31, 2004
(in millions)

	Utility Operations	Investments-Gas Operations	Investments-UK Operations	Total
Current Assets	$ 392	$ 255	$ 1	$ 648
Noncurrent Assets	354	115	-	469
Total Assets	746	370	1	1,117
Current Liabilities	(282)	(236)	(11)	(529)
Noncurrent Liabilities	(187)	(134)	(2)	(323)
Total Liabilities	(469)	(370)	(13)	(852)
Total Net Assets (Liabilities), excluding Hedges	$ 277	$ -	$ (12)	$ 265

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of December 31, 2004
(in millions)

	MTM Risk Management Contracts (a)	PLUS: Hedges	Total (b)
Current Assets	$ 648	$ 89	$ 737
Noncurrent Assets	469	1	470
Total MTM Derivative Contract Assets	1,117	90	1,207
Current Liabilities	(529)	(79)	(608)
Noncurrent Liabilities	(323)	(6)	(329)
Total MTM Derivative Contract Liabilities	(852)	(85)	(937)
Total MTM Derivative Contract Net Assets	$ 265	$ 5	$ 270

(a) Does not include Cash Flow and Fair Value Hedges.
(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets (Liabilities)

The table presenting maturity and source of fair value of MTM risk management contract net assets (liabilities) provides two fundamental pieces of information.

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of December 31, 2004
(in millions)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ (47)	$ 1	$ 9	$ -	$ -	$ -	$ (37)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	163	44	34	13	-	-	254
Prices Based on Models and Other Valuation Methods (b)	(6)	(8)	2	19	25	28	60
Total	$ 110	$ 37	$ 45	$ 32	$ 25	$ 28	$ 277
Investments - Gas Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ 21	$ (4)	$ 2	$ -	$ -	$ -	$ 19
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(4)	(6)	-	-	-	-	(10)
Prices Based on Models and Other Valuation Methods (b)	2	(1)	(1)	(3)	(4)	(2)	(9)
Total	$ 19	$ (11)	$ 1	$ (3)	$ (4)	$ (2)	$ -
Investments - UK Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(10)	(2)	-	-	-	-	(12)
Prices Based on Models and Other Valuation Methods (b)	-	-	-	-	-	-	-
Total	$ (10)	$ (2)	$ -	$ -	$ -	$ -	$ (12)
Total:							
Prices Actively Quoted – Exchange Traded Contracts	$ (26)	$ (3)	$ 11	$ -	$ -	$ -	$ (18)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	149	36	34	13	-	-	232
Prices Based on Models and Other Valuation Methods (b)	(4)	(9)	1	16	21	26	51
Total	$ 119	$ 24	$ 46	$ 29	$ 21	$ 26	$ 265

(a) Prices provided by other external sources – Reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) Modeled – In the absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity is limited, such valuations are classified as modeled.
(c) Amounts exclude Cash Flow and Fair Value Hedges.

The determination of the point at which a market is no longer liquid for placing it in the Modeled category in the preceding table varies by market. The following table reports an estimate of the maximum tenors (contract maturities) of the liquid portion of each energy market.

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of December 31, 2004

Commodity	Transaction Class	Market/Region	Tenor (in months)
Natural Gas	Futures	NYMEX/Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	24
	Swaps	Gas East – Northeast, Mid-continent, Gulf Coast, Texas	24
	Swaps	Gas West – Rocky Mountains, West Coast	22
	Exchange Option Volatility	NYMEX/Henry Hub	12
Power	Futures	Power East – PJM	36
	Physical Forwards	Power East – Cinergy	24
	Physical Forwards	Power East – PJM West	36
	Physical Forwards	Power East – AEP Dayton (PJM)	24
	Physical Forwards	Power East – NEPOOL	12
	Physical Forwards	Power East – NYPP	24
	Physical Forwards	Power East – ERCOT	48
	Physical Forwards	Power East – Com Ed	24
	Physical Forwards	Power East – Entergy	12
	Physical Forwards	Power West – Palo Verde, North Path 15, South Path 15, MidColumbia, Mead	36
	Peak Power Volatility (Options)	Cinergy	12
	Peak Power Volatility (Options)	PJM	12
Crude Oil	Swaps	West Texas Intermediate	36
Emissions	Credits	SO_2, NO_x	48
Coal	Physical Forwards	PRB, NYMEX, CSX	24

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power and gas operations. We monitor these risks on our future operations and may employ various commodity instruments and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ cash flow hedges to mitigate changes in interest rates or fair values on short-term and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. We do not hedge all foreign currency exposure.

The tables below provide detail on effective cash flow hedges under SFAS 133 included in our Balance Sheets. The data in the first table will indicate the magnitude of SFAS 133 hedges that we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. This table further indicates what portions of these hedges are expected to be reclassified into net income in the next 12 months. The second table provides the nature of changes from December 31, 2003 to December 31, 2004.

Information on energy activities is presented separately from interest rate and foreign currency risk management activities. In accordance with GAAP, all amounts are presented net of related income taxes.

Cash Flow Hedges included in Accumulated Other Comprehensive Loss
On the Balance Sheet as of December 31, 2004
(in millions)

	Accumulated Other Comprehensive Income (Loss) After Tax (a)	Portion Expected to be Reclassified to Earnings During the Next 12 Months (b)
Power and Gas	$ 23	$ 26
Foreign Currency	-	-
Interest Rate	(23)	(4)
Total	$ -	$ 22

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2004
(in millions)

	Power, Gas and Coal	Foreign Currency	Interest Rate	Total
Beginning Balance, December 31, 2003	$ (65)	$ (20)	$ (9)	$ (94)
Changes in Fair Value (c)	29	-	(21)	8
Reclassifications from AOCI to Net Income (d)	59	20	7	86
Ending Balance, December 31, 2004	$ 23	$ -	$ (23)	$ -

(a) "Accumulated Other Comprehensive Income (Loss) After Tax" – Gains/losses are net of related income taxes that have not yet been included in the determination of net income; reported as a separate component of shareholders' equity on the balance sheet.
(b) "Portion Expected to be Reclassified to Earnings During the Next 12 Months" – Amount of gains or losses (realized or unrealized) from derivatives used as hedging instruments that have been deferred and are expected to be reclassified into net income during the next 12 months at the time the hedged transaction affects net income.
(c) "Changes in Fair Value" – Changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.
(d) "Reclassifications from AOCI to Net Income" – Gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

Credit Risk

We limit credit risk by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. Only after an entity has met our internal credit rating criteria will we extend unsecured credit. We use Moody's Investor Service, Standard and Poor's and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. Our analysis, in conjunction with the rating agencies' information, is used to determine appropriate risk parameters. We also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties depending upon credit quality in our normal course of business.

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. At December 31, 2004, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 14.5%, expressed in terms of net MTM assets and net receivables. The concentration in noninvestment grade credit exposure is proportionately higher due to coal exposures related to domestic MTM coal transactions. These exposures were driven by the continued high levels of prices for coal. As of December 31, 2004, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%
Investment Grade	$ 789	$ 147	$ 642	-	$ -
Split Rating	87	21	66	3	48
Noninvestment Grade	230	134	96	3	68
No External Ratings:					
Internal Investment Grade	161	1	160	3	80
Internal Noninvestment Grade	61	11	50	1	10
Total	$ 1,328	$ 314	$ 1,014	10	$ 206

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged, including both contracts designated as cash flow hedges under SFAS 133 and contracts not designated as cash flow hedges. This information is forward-looking and provided on a prospective basis through December 31, 2007. Please note that this table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged" represents the portion of MWHs of future generation/production for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of December 31, 2004

	2005	2006	2007
Estimated Plant Output Hedged	93%	94%	93%

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (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, at December 31, 2004, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

VaR Model

December 31, 2004 (in millions)				December 31, 2003 (in millions)			
End	High	Average	Low	End	High	Average	Low
$3	$19	$5	$1	$11	$19	$7	$4

The 2004 High VaR occurred in January 2004 during a period when international coal and freight prices experienced record high levels and extreme volatility. Within the following month, the VaR returned to levels approaching the average VaR for the year.

Our VaR model results are adjusted using standard statistical treatments to calculate the CCRO VaR reporting metrics listed below.

CCRO VaR Metrics
(in millions)

	December 31, 2004	Average for Year-to-Date 2004	High for Year-to-Date 2004	Low for Year-to-Date 2004
95% Confidence Level, Ten-Day Holding Period	$ 10	$ 20	$ 73	$ 5
99% Confidence Level, One-Day Holding Period	$ 4	$ 8	$ 30	$ 2

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $601 million at December 31, 2004 and $1 billion at December 31, 2003. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or consolidated financial position.

We employ risk management contracts including physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps, and other derivative contracts to offset price risk where appropriate. We engage in risk management of electricity, gas and to a lesser degree other commodities, principally coal and emissions. As a result, we are subject to price risk. The amount of risk taken is controlled by risk management operations and our Chief Risk Officer and his staff. When risk management activities exceed certain pre-determined limits, the positions are modified or hedged to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

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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, 2004 and 2003, and the related consolidated statements of operations, cash flows, and common shareholders' equity and comprehensive income (loss), for each of the three years in the period ended December 31, 2004. 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, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 142, "Goodwill and Other Intangible Assets," effective January 1, 2002; SFAS 143, "Accounting for Asset Retirement Obligations," and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003; FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003; and FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*, that American Electric Power Company, Inc. and subsidiary companies (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, 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 and the financial statement schedules as of and for the year ended December 31, 2004 of the Company and our reports dated February 28, 2005 expressed an unqualified opinion on those financial statements and the financial statement schedules and included an explanatory paragraph regarding the Company's adoption of a new accounting pronouncements in 2002, 2003 and 2004.

Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

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.

AEP management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2004. In making this assessment we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework*. Based on our assessment, the company's internal control over financial reporting was effective as of December 31, 2004.

AEP's independent registered public accounting firm has issued an attestation report on our assessment of the Company's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on page 68.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2004, 2003 and 2002
(in millions, except per-share amounts)

	2004	2003	2002
REVENUES			
Utility Operations	$ 10,513	$ 10,869	$ 10,446
Gas Operations	3,064	3,099	2,071
Other	480	699	910
TOTAL	14,057	14,667	13,427
EXPENSES			
Fuel for Electric Generation	2,949	3,058	2,580
Purchased Energy for Resale	689	707	532
Purchased Gas for Resale	2,807	2,850	1,946
Maintenance and Other Operation	3,611	3,660	4,054
Asset Impairments and Other Related Charges	-	650	318
Depreciation and Amortization	1,300	1,307	1,356
Taxes Other Than Income Taxes	710	681	718
TOTAL	12,066	12,913	11,504
OPERATING INCOME	1,991	1,754	1,923
Interest Income	33	25	21
Carrying Costs on Texas Stranded Cost Recovery	302	-	-
Investment Value Losses	(15)	(70)	(321)
Gain on Disposition of Equity Investments, Net	153	-	-
Other Income	205	240	321
Other Expense	(183)	(229)	(323)
INTEREST AND OTHER CHARGES			
Interest Expense	781	814	775
Preferred Stock Dividend Requirements of Subsidiaries	6	9	11
Minority Interest in Finance Subsidiary	-	17	35
TOTAL	787	840	821
INCOME BEFORE INCOME TAXES	1,699	880	800
Income Taxes	572	358	315
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES	1,127	522	485
DISCONTINUED OPERATIONS, Net of Tax	83	(605)	(654)
EXTRAORDINARY LOSS ON TEXAS STRANDED COST RECOVERY, Net of Tax	(121)	-	-
CUMULATIVE EFFECT OF ACCOUNTING CHANGES, Net of Tax			
Goodwill and Other Intangible Assets	-	-	(350)
Accounting for Risk Management Contracts	-	(49)	-
Asset Retirement Obligations	-	242	-
NET INCOME (LOSS)	$ 1,089	$ 110	$ (519)
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING	396	385	332
EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes	$ 2.85	$ 1.35	$ 1.46
Discontinued Operations	0.21	(1.57)	(1.97)
Extraordinary Loss	(0.31)	-	-
Cumulative Effect of Accounting Changes	-	0.51	(1.06)
TOTAL EARNINGS PER SHARE (BASIC AND DILUTIVE)	$ 2.75	$ 0.29	$ (1.57)
CASH DIVIDENDS PAID PER SHARE	$ 1.40	$ 1.65	$ 2.40

See Notes to Consolidated Financial Statements

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in millions)

	2004	2003
CURRENT ASSETS		
Cash and Cash Equivalents	$ 420	$ 976
Other Cash Deposits	175	206
Accounts Receivable:		
Customers	930	1,155
Accrued Unbilled Revenues	592	596
Miscellaneous	79	83
Allowance for Uncollectible Accounts	(77)	(124)
Total Receivables	1,524	1,710
Fuel, Materials and Supplies	852	889
Risk Management Assets	737	766
Margin Deposits	113	119
Other	200	161
TOTAL	4,021	4,827
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	15,969	15,112
Transmission	6,293	6,130
Distribution	10,280	9,902
Other (including gas, coal mining and nuclear fuel)	3,585	3,590
Construction Work in Progress	1,159	1,287
Total	37,286	36,021
Accumulated Depreciation and Amortization	14,485	14,004
TOTAL - NET	22,801	22,017
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,601	3,582
Securitized Transition Assets	642	689
Spent Nuclear Fuel and Decommissioning Trusts	1,053	982
Investments in Power and Distribution Projects	154	212
Goodwill	76	78
Long-term Risk Management Assets	470	494
Prepaid Pension Obligations	386	-
Other	831	806
TOTAL	7,213	6,843
Assets of Discontinued Operations and Held for Sale	628	3,094
TOTAL ASSETS	$ 34,663	$ 36,781

See Notes to Consolidated Financial Statements

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2004 and 2003

	2004	2003
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$ 1,051	$ 1,337
Short-term Debt	23	326
Long-term Debt Due Within One Year (a)	1,279	1,779
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption (a)	66	-
Risk Management Liabilities	608	631
Accrued Taxes	611	620
Accrued Interest	180	207
Customer Deposits	414	379
Other	775	703
TOTAL	5,007	5,982
NONCURRENT LIABILITIES		
Long-term Debt (a)	11,008	12,322
Long-term Risk Management Liabilities	329	335
Deferred Income Taxes	4,819	3,957
Regulatory Liabilities and Deferred Investment Tax Credits	2,540	2,395
Asset Retirement Obligations	827	651
Employee Benefits and Pension Obligations	730	667
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	166	176
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption (a)	-	76
Deferred Credits and Other	411	409
TOTAL	20,830	20,988
Liabilities of Discontinued Operations and Held for Sale	250	1,876
TOTAL LIABILITIES	26,087	28,846
Cumulative Preferred Stock Not Subject to Mandatory Redemption (a)	61	61
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		
2004 / 2003		
Shares Authorized 600,000,000 / 600,000,000		
Shares Issued 404,858,145 / 404,016,413		
(8,999,992 shares were held in treasury at December 31, 2004 and 2003)	2,632	2,626
Paid-in Capital	4,203	4,184
Retained Earnings	2,024	1,490
Accumulated Other Comprehensive Income (Loss)	(344)	(426)
TOTAL	8,515	7,874
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 34,663	$ 36,781

(a) See Accompanying Schedules.

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, 2004, 2003 and 2002
(in millions)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income (Loss)	$ 1,089	$ 110	$ (519)
Plus: (Income) Loss from Discontinued Operations	(83)	605	654
Income from Continuing Operations	1,006	715	135
Adjustments for Noncash Items:			
Depreciation and Amortization	1,300	1,307	1,356
Accretion of Asset Retirement Obligations	64	59	-
Deferred Income Taxes	291	163	63
Deferred Investment Tax Credits	(29)	(33)	(31)
Cumulative Effect of Accounting Changes	-	(193)	350
Asset Impairments, Investment Value Losses and Other Related Charges	15	720	639
Carrying Costs on Stranded Cost Recovery	(302)	-	-
Extraordinary Loss	121	-	-
Amortization of Deferred Property Taxes	(3)	(2)	(16)
Amortization of Cook Plant Restart Costs	-	40	40
Mark-to-Market of Risk Management Contracts	14	(122)	275
Pension Contributions	(231)	(58)	-
Over/Under Fuel Recovery	96	239	13
Gain on Sales of Assets	(159)	(48)	(117)
Change in Other Noncurrent Assets	(187)	(137)	(91)
Change in Other Noncurrent Liabilities	134	(171)	(124)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	298	363	(238)
Fuel, Materials and Supplies	33	(52)	(73)
Accounts Payable	(325)	(632)	(21)
Taxes Accrued	427	87	(222)
Customer Deposits	35	194	23
Interest Accrued	-	(5)	72
Other Current Assets	(35)	(5)	65
Other Current Liabilities	34	(121)	(31)
Net Cash Flows From Operating Activities	2,597	2,308	2,067
INVESTING ACTIVITIES			
Construction Expenditures	(1,693)	(1,358)	(1,685)
Change in Other Cash Deposits, Net	31	(91)	(84)
Investment in Discontinued Operations, Net	(59)	(615)	-
Proceeds from Sale of Assets	1,357	82	1,263
Other	(12)	3	44
Net Cash Flows Used For Investing Activities	(376)	(1,979)	(462)
FINANCING ACTIVITIES			
Issuance of Common Stock	17	1,142	656
Issuance of Long-term Debt	682	4,761	2,893
Issuance of Equity Unit Senior Notes	-	-	334
Change in Short-term Debt, Net	(400)	(2,781)	(1,248)
Retirement of Long-term Debt	(2,511)	(2,707)	(2,513)
Retirement of Preferred Stock	(10)	(9)	(10)
Retirement of Minority Interest	-	(225)	-
Dividends Paid on Common Stock	(555)	(618)	(793)
Net Cash Flows Used For Financing Activities	(2,777)	(437)	(681)
Effect of Exchange Rate Change on Cash	-	-	(3)
Net Increase (Decrease) in Cash and Cash Equivalents	(556)	(108)	921
Cash and Cash Equivalents at Beginning of Period	976	1,084	163
Cash and Cash Equivalents at End of Period	$ 420	$ 976	$ 1,084
Net Increase (Decrease) in Cash and Cash Equivalents from Discontinued Operations	$ (13)	$ (10)	$ (116)
Cash and Cash Equivalents from Discontinued Operations – Beginning of Period	13	23	139
Cash and Cash Equivalents from Discontinued Operations – End of Period	$ -	$ 13	$ 23

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(in millions)

	Common Stock					
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	331	$ 2,153	$ 2,906	$ 3,296	$ (126)	$ 8,229
Issuance of Common Stock	17	108	568			676
Common Stock Dividends				(793)		(793)
Common Stock Expense			(30)			(30)
Other			(31)	15		(16)
TOTAL						8,066
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					117	117
Cash Flow Hedges, Net of Tax of $2					(13)	(13)
Securities Available for Sale, Net of Tax of $1					(2)	(2)
Minimum Pension Liability, Net of Tax of $315					(585)	(585)
NET LOSS				(519)		(519)
TOTAL COMPREHENSIVE LOSS						(1,002)
DECEMBER 31, 2002	348	2,261	3,413	1,999	(609)	7,064
Issuance of Common Stock	56	365	812			1,177
Common Stock Dividends				(618)		(618)
Common Stock Expense			(35)			(35)
Other			(6)	(1)		(7)
TOTAL						7,581
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					106	106
Cash Flow Hedges, Net of Tax of $42					(78)	(78)
Securities Available for Sale, Net of Tax of $0					1	1
Minimum Pension Liability, Net of Tax of $75					154	154
NET INCOME				110		110
TOTAL COMPREHENSIVE INCOME						293
DECEMBER 31, 2003	404	2,626	4,184	1,490	(426)	7,874
Issuance of Common Stock	1	6	11			17
Common Stock Dividends				(555)		(555)
Other			8			8
TOTAL						7,344
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(104)	(104)
Cash Flow Hedges, Net of Tax of $51					94	94
Minimum Pension Liability, Net of Tax of $52					92	92
NET INCOME				1,089		1,089
TOTAL COMPREHENSIVE INCOME						1,171
DECEMBER 31, 2004	405	$ 2,632	$ 4,203	$ 2,024	$ (344)	$ 8,515

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES
December 31, 2004 and 2003

	December 31, 2004			
	Call Price Per Share (a)	**Shares Authorized (b)**	**Shares Outstanding (d)**	**Amount (in millions)**
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	607,662	$ 61
Subject to Mandatory Redemption:				
5.90% (c)	$100	850,000	182,000 (f)	18
6.25% - 6.875% (c)	$100	950,000	482,450 (f)	48
Total Subject to Mandatory Redemption (c)				66
Total Preferred Stock				$ 127(e)

	December 31, 2003			
	Call Price Per Share (a)	**Shares Authorized (b)**	**Shares Outstanding (d)**	**Amount (in millions)**
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	607,940	$ 61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	$100	1,950,000	278,100	28
6.25% - 6.875% (c)	$100	950,000	482,450	48
Total Subject to Mandatory Redemption (c)				76
Total Preferred Stock				$ 137 (e)

(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.

(b) As of December 31, 2004, the subsidiaries had 13,823,127 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,822,164 shares of no par value preferred stock that were authorized but unissued. As of December 31, 2003, the subsidiaries had 13,780,352 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,768,561 shares of no par value preferred stock that were authorized but unissued.

(c) Shares outstanding and related amounts are stated net of applicable retirements through sinking funds (generally at par) and reacquisitions of shares in anticipation of future requirements. The subsidiaries reacquired enough shares in 1997 to meet all sinking fund requirements on certain series until 2008 and on certain series until 2009 when all remaining outstanding shares must be redeemed.

(d) The number of shares of preferred stock redeemed is 96,378 shares in 2004, 86,210 shares in 2003 and 106,458 shares in 2002.

(e) Due to the implementation of SFAS 150 in July 2003, Cumulative Preferred Stocks of Subsidiaries is no longer presented as one line item on the balance sheet. SFAS 150 has required us to present Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption as a liability. Cumulative Preferred Stocks of Subsidiaries Not Subject to Mandatory Redemption will continue to be reported separately on the balance sheet.

(f) All outstanding shares were redeemed on January 3, 2005.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
December 31, 2004 and 2003

Maturity	Weighted Average Interest Rate December 31, 2004	Interest Rates at December 31, 2004	Interest Rates at December 31, 2003	December 31, 2004	December 31, 2003
				(in millions)	
FIRST MORTGAGE BONDS (a)					
2004-2008 (b)	6.91%	6.20%-8.00%	6.125%-8.00%	$ 456	$ 694
2024-2025	8.00%	8.00%	6.875%-8.00%	45	246
INSTALLMENT PURCHASE CONTRACTS (c)					
2004-2009	3.58%	1.75%-4.55%	2.15%-6.90%	163	350
2011-2022	3.98%	1.70%-6.10%	1.10%-8.20%	785	943
2023-2038	4.39%	1.125%-6.55%	1.20%-6.55%	825	733
NOTES PAYABLE (d)					
2004-2017	4.98%	2.325%-15.25%	1.537%-15.45%	939	1,518
SENIOR UNSECURED NOTES					
2004-2009	5.22%	2.879%-6.91%	2.43%-7.45%	3,459	3,707
2010-2015	5.30%	4.40%-6.375%	4.40%-6.375%	2,633	2,525
2032-2038	6.32%	5.625%-6.65%	5.625%-7.375%	1,625	1,765
SECURITIZATION BONDS					
2007-2017	5.67%	3.54%-6.25%	3.54%-6.25%	698	746
NOTES PAYABLE TO TRUST					
2037-2043	5.25%	5.25%	5.25%-8.00%	113	331
EQUITY UNIT SENIOR NOTES (e)					
2007	5.75%	5.75%	5.75%	345	345
OTHER LONG-TERM DEBT (f)				243	247
Equity Unit Contract Adjustment Payments (g)				9	19
Unamortized Discount (net)				(51)	(68)
Total Long-term Debt Outstanding				12,287	14,101
Less Portion Due Within One Year				1,279	1,779
Long-term Portion				$ 11,008	$ 12,322

(a) First mortgage bonds are secured by first mortgage liens on electric property, plant and equipment. There are certain limitations on establishing additional liens against our assets under our indentures.
(b) In May 2004, we deposited cash and treasury securities with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had balances of $84 million and $118 million in 2004 and 2003, respectively. Trust fund assets related to this obligation of $72 million are included in Other Cash Deposits and $22 million are included in Other Noncurrent Assets in the Consolidated Balance Sheets at December 31, 2004. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.
(c) For certain series of installment purchase contracts, interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and standby bond purchase agreements support certain series.
(d) 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.
(e) In May 2005, the interest rate on these Equity Unit Senior Notes can be reset through a remarketing.
(f) Other long-term debt consists of fair market value of adjustments of fixed rate debt that is hedged, a liability along with accrued interest for disposal of spent nuclear fuel (see "Nuclear" section of Note 7) and a financing obligation under a sale and leaseback agreement.
(g) The Equity Unit Contract Adjustment Payments settle in August 2005 and as a result the amount is classified as due within one year.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2004 IS PAYABLE AS FOLLOWS:

	2005	2006	2007	2008	2009	After 2009	Total
				(in millions)			
Principal Amount	$ 1,279	$ 1,659	$ 1,262	$ 575	$ 402	$ 7,161	$ 12,338
Unamortized Discount							(51)
							$ 12,287

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by our eleven domestic electric utility operating companies is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions. During 2003, we announced plans to significantly restructure and dispose of our nonregulated operations. See Note 10 for a discussion of the impacts of these plans on our organization.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our domestic operations include nonregulated independent power and cogeneration facilities, coal mining and intra-state natural gas operations in Texas. In January 2005, we sold a 98% interest in our natural gas operations in Texas. We sold our natural gas operations in Louisiana in 2004.

We are in the process of completing our divestitures of our noncore assets, including most of our international operations. Our current international portfolio includes only limited investments in the generation and supply of power in Mexico and the Pacific Rim. We sold our generation assets in the U.K. and China in 2004. In 2002, we sold our investments in international distribution companies in Australia and the U.K.

We also conduct domestic barging operations and provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

We are subject to regulation by the SEC under the PUHCA. The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations. Wholesale power markets are generally market-based and are not cost-based regulated unless a generator/seller of wholesale power is determined by the FERC to have "market power." The FERC also regulates transmission service and rates particularly in states that have restructured and unbundled their rates. The state commissions regulate all or portions of our retail operations and retail rates dependent on the status of customer choice in each state jurisdiction (see Note 6).

Principles of Consolidation

Our consolidated financial statements include AEP and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries or substantially controlled variable interest entities (VIE). Intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Other Income. We also consolidate variable interest entities in accordance with FASB Interpretation Number (FIN) 46 (revised December 2003) "Consolidation of Variable Interest Entities" (FIN 46R) (see Note 2). We also have generating units that are jointly owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Operations and the investments are reflected in our Consolidated Balance Sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of cost-based rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation", regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. We discontinued the application of SFAS 71 for the generation portion of our business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by TCC, TNC, and SWEPCo in September 1999, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December 2003. During 2003, APCo reapplied SFAS 71 for its West Virginia generation operations and SWEPCo reapplied SFAS 71 for its Arkansas generation operations. SFAS 101, "Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71" requires the recognition of an impairment of a regulatory asset arising from the discontinuance of SFAS 71 be classified as an extraordinary item.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, goodwill and intangible asset impairment, unbilled electricity revenue, values of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension 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 differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the nonregulated operations and other investments are stated at their fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are charged to accumulated depreciation. For nonregulated operations, retirements from the plant accounts, net of salvage, are charged to accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses.

We implemented SFAS 143 effective January 1, 2003 (see "Accounting for Asset Retirement Obligations (ARO)" section of this note).

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets is no longer recoverable or when the assets meet the held for sale criteria under SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Equity investments are required to be tested for impairment when it is determined that an other than temporary loss in value has occurred.

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

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment on a straight-line basis over the estimated useful lives of property, excluding coal-mining properties, generally using composite rates by functional class as follows:

Functional Class of Property	**Annual Composite Depreciation Rate Ranges**		
	2004	**2003**	**2002**
Production:			
Steam-Nuclear	3.1%	2.5% to 3.4%	2.5% to 3.4%
Steam-Fossil-Fired	2.6% to 4.5%	2.3% to 4.6%	2.6% to 4.5%
Hydroelectric-Conventional and Pumped Storage	2.6% to 3.3%	1.9% to 3.4%	1.9% to 3.4%
Transmission	1.7% to 3.0%	1.7% to 3.1%	1.7% to 3.0%
Distribution	3.2% to 4.1%	3.3% to 4.2%	3.3% to 4.2%
Other	4.9% to 16.4%	5.2% to 16.7%	4.7% to 9.9%

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. Average amortization rates for coal rights and mine development costs were $0.65 per ton in 2004, $0.25 per ton in 2003 and $0.32 per ton in 2002. In 2004, average amortizations rates increased from 2003 due to a lower tonnage nomination from the power plant yielding a higher cost per ton. In addition, coal mining assets amortized at a lower rate were sold in 2004. In 2002, certain coal-mining assets were impaired by $60 million leading to the decline in amortization rates in 2003.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to accumulated depreciation. Actual removal costs incurred are debited to accumulated depreciation. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from accumulated depreciation and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred (see “Accounting for Asset Retirement Obligations (ARO)” section of this note).

Accounting for Asset Retirement Obligations (ARO)

We implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. ARO accounting is being followed for regulated and nonregulated property that has a legal removal obligation. Upon removal of ARO property, any difference between the ARO accrual and actual removal costs is recognized as income or expense.

The following is a reconciliation of 2003 and 2004 aggregate carrying amount of asset retirement obligations:

	Nuclear Decommissioning	Ash Ponds	U.K. Plants, Wind Mills and Mining Operations	Total
		(in millions)		
ARO Liability at January 1, 2003 Including Held for Sale	$ 718.3	$ 69.8	$ 37.2	$ 825.3
Accretion Expense	52.6	5.6	2.3	60.5
Liabilities Incurred	-	-	8.3	8.3
Foreign Currency Translation	-	-	5.3	5.3
ARO Liability at December 31, 2003 Including Held for Sale	770.9	75.4	53.1	899.4
Less ARO Liability Held for Sale:				
South Texas Project (b)	(218.8)	-	-	(218.8)
U.K. Plants		-	(28.8)	(28.8)
ARO Liability at December 31, 2003	$ 552.1	$ 75.4	$ 24.3	$ 651.8
ARO Liability at January 1, 2004 Including Held for Sale	$ 770.9	$ 75.4	$ 53.1	$ 899.4
Accretion Expense	56.5	6.0	2.8	65.3
Foreign Currency Translation	-	-	0.6	0.6
Liabilities Incurred	-	-	17.7	17.7
Liabilities Settled (a)	-	(0.4)	(56.9)	(57.3)
Revisions in Cash Flow Estimates	132.1	3.2	15.0	150.3
ARO Liability at December 31, 2004 Including Held for Sale	959.5	84.2	32.3	1,076.0
Less ARO Liability Held for Sale:				
South Texas Project (b)	(248.9)	-	-	(248.9)
ARO Liability at December 31, 2004	$ 710.6	$ 84.2	$ 32.3	$ 827.1

(a) Liabilities settled include approximately $45.5 million in noncash reductions of ARO associated with the sale of the U.K. generation assets in July 2004.
(b) We have signed an agreement to sell TCC's share of South Texas Project (see Note 10).

Accretion expense is included in Maintenance and Other Operation expense in our accompanying Consolidated Statements of Operations.

As of December 31, 2004 and 2003, the fair values of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $934 million and $845 million, respectively, of which $791 million and $720 million relating to the Cook Plant are recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Consolidated Balance Sheets. The fair values of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities for the South Texas Project totaling $143 million and $125 million as of December 31, 2004 and 2003, respectively, are classified as Assets of Discontinued Operations and Held for Sale in our Consolidated Balance Sheets.

Pro forma net income and earnings per share are not presented for the year ended December 31, 2002 because the pro forma application of SFAS 143 would result in pro forma net income and earnings per share not materially different from the actual amounts reported during that period.

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 domestic regulated electric utility plant. For nonregulated operations, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of

Interest Costs." Capitalized interest is also recorded for domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting. The amounts of AFUDC and interest capitalized were $37 million, $37 million and $34 million in 2004, 2003 and 2002, respectively.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Other Cash Deposits, 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.

Cash and Cash Equivalents

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

Other Cash Deposits

Other Cash Deposits include funds held by trustees primarily for the payment of debt.

Inventory

Except for PSO and TNC, the domestic utility companies value fossil fuel inventories at the lower of a weighted average cost or market. PSO and TNC record fossil fuel inventories at the lower of cost or market, utilizing the LIFO cost method. Materials and supplies inventories are carried at average cost. Gas inventory is carried at the lower of weighted average cost or market. During 2003, a fair value hedging strategy was implemented for certain gas inventory. Changes in the fair value of hedged inventory were recorded to the extent offsetting hedges are designated against that inventory. In the third quarter of 2004, the fair value hedges were de-designated. As a result, the existing hedged inventory was held at the market price on the fair value hedge de-designation date with subsequent additions to inventory carried at 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 and gas sales when we deliver power or gas 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, an estimate of the revenues for energy delivered since the last billing.

AEP Credit, Inc. factors accounts receivable for certain subsidiaries, including CSPCo, I&M, 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 sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be removed from the company's balance sheets (see "Sale of Receivables" section of Note 17).

Foreign Currency Translation

The financial statements of subsidiaries outside the U.S. that are included in our consolidated financial statements and investments outside the U.S. that are accounted for under the equity method are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52, "Foreign Currency Translation." Although the effects of foreign currency fluctuations are mitigated by the fact that expenses of foreign subsidiaries are generally incurred in the same currencies in which sales are generated, the reported results of operations of our foreign subsidiaries are affected by changes in foreign currency exchange rates and, as compared to prior periods, will be higher or lower depending upon a weakening or strengthening of the U.S. dollar. Revenues and expenses are translated at monthly average foreign currency exchange rates throughout the year. Assets and liabilities are translated into U.S. dollars at year-end foreign currency exchange rates. Accordingly, our consolidated common shareholders' equity will fluctuate depending on the relative strengthening or weakening of the U.S. dollar versus relevant foreign currencies. Currency translation gain and loss adjustments are recorded in shareholders' equity as Accumulated Other Comprehensive Income (Loss). The balance of Accumulated Other Comprehensive Income as of December 31, 2004 has been reduced significantly primarily due to the disposition of our U.K. assets in 2004, which is reflected in Discontinued Operations on our Consolidated Statements of Operations. The impact of the changes in exchange rates on cash, resulting from the translation of items at different exchange rates, is shown on our Consolidated Statements of Cash Flows in Effect of Exchange Rate Change on Cash. Actual currency transaction gains and losses are recorded in income when they occur.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulator's review and approval. The amounts of an over-recovery or under-recovery can also be affected by actions of regulators. When a fuel cost disallowance becomes probable, we adjust our deferrals and record provisions for estimated refunds to recognize these probable outcomes (see Note 4).

In general, changes in fuel costs in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All or a portion of profits from off-system sales are shared with ratepayers through fuel clauses in Texas (SPP area only), Oklahoma, Louisiana, Arkansas, Kentucky and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing, (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002) changes in fuel costs impact earnings unless recovered in the sales price for electricity. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes have impacted earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze ended on March 1, 2004. Through subsequent orders, the Indiana Utility Regulatory Commission (IURC) has authorized the billing of capped fuel rates on an interim basis until April 1, 2005. In Indiana, there is an issue as to whether the freeze should be extended through 2007 under an existing corporate separation stipulation agreement. Management disagrees with this interpretation of the stipulation and the matter is pending resolution. In West Virginia, the fuel clause is suspended indefinitely. Changes in fuel costs also impact earnings for certain of our IPP generating units that do not have long-term contracts for their fuel supply or have not hedged fuel costs (see Notes 4 and 6).

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 to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets also reduces future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our statement of operations when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase and sale contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio, Virginia and Texas. 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).

For power purchased under derivative contracts in AEP's west zone where we are short capacity, prior to settlement the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period are recognized as Revenues. If the contract results in the physical delivery of power, the previously recorded unrealized gains and losses from MTM valuations are reversed and the settled amounts are recorded gross as Purchased Energy for Resale. If the contract does not physically deliver, the previously recorded unrealized gains and losses from MTM valuations are reversed and the settled amounts are recorded as Revenues in the Consolidated Statement of Operations on a net basis (see Note 14).

Domestic Gas Pipeline and Storage Activities

Revenues are recognized from domestic gas pipeline and storage services when gas is delivered to contractual meter points or when services are provided, with the exception of certain physical forward gas purchase and sale contracts that are derivatives and accounted for using MTM accounting (resale gas contracts). The unrealized and realized gains and losses on resale gas contracts for the sale of natural gas are presented as Revenues in the Consolidated Statement of Operations. The unrealized and realized gains and losses on physically settled resale gas contracts for the purchase of natural gas are presented as Purchased Gas for Resale in the Consolidated Statement of Operations (see Note 14).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities. Effective October 2002, these activities were focused on wholesale markets where we own assets. 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, and over-the-counter options and swaps. Prior to October 2002, we recorded wholesale marketing and risk management activities using the MTM method of accounting.

In October 2002, EITF 02-3 precluded MTM accounting for risk management contracts that were not derivatives pursuant to SFAS 133. We implemented this standard for all nonderivative wholesale and risk management transactions occurring on or after October 25, 2002. For nonderivative risk management transactions entered prior to October 25, 2002, we implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change (see "Accounting for Risk Management Contracts" section of Note 2).

After January 1, 2003, revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. The unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in Revenues in the Consolidated Statement of Operations on a net basis. In jurisdictions subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain wholesale marketing and risk management transactions are designated as a hedge of a forecasted transaction, a future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the Consolidated Statement of Operations in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income and subsequently reclassified into Revenues in the Consolidated Statement of Operations when the forecasted transaction is realized and affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the Consolidated Statement of Operations immediately (see Note 14).

Construction Projects for Outside Parties

We engage in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as project costs are incurred and billed to the outside party.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that we will recover specifically incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. Maintenance costs during refueling outages at the Cook Nuclear Plant are deferred and amortized over the period between outages in accordance with rate orders in Indiana and Michigan.

Other Income and Other Expense

Nonoperational revenue including the nonregulated business activities of our utilities, equity earnings of nonconsolidated subsidiaries, gains on dispositions of property, AFUDC-equity and miscellaneous income, are reported in Other Income. Nonoperational expenses including nonregulated business activities of our utilities, losses on dispositions of property, miscellaneous amortization, donations and various other nonrecoverable/nonoperating and miscellaneous expenses, are reported in Other Expense.

AEP Consolidated Other Income and Other Expense:

	December 31,		
	2004	**2003**	**2002**
		(in millions)	
Other Income:			
Equity Earnings (Loss)	$ 18	$ 10	$ (15)
Nonutility Revenue	127	129	201
Gain on Sale of REPs (Mutual Energy Companies)	-	39	129
Other	60	62	6
Total Other Income	$ 205	$ 240	$ 321
Other Expense:			
Nonutility Expense	$ 103	$ 112	$ 179
Property and Miscellaneous Taxes	20	20	20
Other	60	97	124
Total Other Expense	$ 183	$ 229	$ 323

Income Taxes and Investment Tax Credits

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

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

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

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 customer. We do not recognize these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Interest Expense.

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

We classify instruments that have an unconditional obligation requiring us to redeem the instruments by transferring an asset at a specified date as liabilities on our Consolidated Balance Sheets. Those instruments consist of Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption as of December 31, 2004 and 2003. Beginning July 1, 2003, we classify dividends on these mandatorily redeemable preferred shares as Interest Expense. In accordance with SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity," dividends from prior periods remain classified as preferred stock dividends, a component of Preferred Stock Dividend Requirements of Subsidiaries, on our Consolidated Statements of Operations.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and reclassified to retained earnings upon the redemption of the entire preferred stock series. The excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries is credited to retained earnings upon reacquisition.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of any assets including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. Purchased goodwill and intangible assets with indefinite lives are not amortized. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. Goodwill is tested at the reporting unit level and other intangibles are tested 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, fair value is estimated using various internal and external valuation methods. Intangible assets with finite lives are amortized over their respective estimated lives, currently ranging from 5 to 10 years, to their estimated residual values.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) and the FERC have established investment limitations and general risk management guidelines. In general, limitations include:

- acceptable investments (rated investment grade or above);
- maximum percentage invested in a specific type of investment;
- prohibition of investment in obligations of the applicable company or its affiliates; and
- withdrawals only for payment of decommissioning costs and trust expenses.

Trust funds are maintained for each regulatory jurisdiction and managed by external investment managers, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Spent Nuclear Fuel and Decommissioning Trusts for amounts relating to the Cook Plant and are included in Assets of Discontinued Operations and Held for Sale for amounts relating to STP (see "Assets Held for Sale" section of Note 10). These securities are recorded at market value. Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Unrealized gains and losses from securities in these trust funds are reported 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.

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)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheets in the common shareholders' equity section. The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

Components	December 31, 2004	December 31, 2003
	(in millions)	
Foreign Currency Translation Adjustments, net of tax	$ 6	$ 110
Securities Available for Sale, net of tax	(1)	(1)
Cash Flow Hedges, net of tax	-	(94)
Minimum Pension Liability, net of tax	(349)	(441)
Total	$ (344)	$ (426)

Stock-Based Compensation Plans

At December 31, 2004, we have two stock-based employee compensation plans with outstanding stock options (see Note 12). No stock option expense is reflected in our earnings, as all options granted under these plans had exercise prices equal to or above the market value of the underlying common stock on the date of grant.

We also grant performance share units, phantom stock units, restricted shares and restricted stock units to employees, as well as stock units to nonemployee members of our Board of Directors. The Deferred Compensation and Stock Plan for Non-Employee Directors permits directors to choose to defer up to 100 percent of their annual Board retainer in stock units, and the Stock Unit Accumulation Plan for Non-Employee Directors awards stock units to directors. Compensation cost is included in Net Income (Loss) for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director's stock units.

The following table shows the effect on our Net Income (Loss) and Earnings (Loss) per Share as if we had applied fair value measurement and recognition provisions of SFAS 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation awards:

	Year Ended December 31,		
	2004	2003	2002
	(in millions, except per share data)		
Net Income (Loss), as reported	$ 1,089	$ 110	$ (519)
Add: Stock-based compensation expense included in reported net income (loss), net of related tax effects	15	2	(5)
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(18)	(7)	(4)
Pro Forma Net Income (Loss)	$ 1,086	$ 105	$ (528)
Earnings (Loss) per Share:			
Basic – As Reported	$ 2.75	$ 0.29	$ (1.57)
Basic – Pro Forma (a)	$ 2.74	$ 0.27	$ (1.59)
Diluted – As Reported	$ 2.75	$ 0.29	$ (1.57)
Diluted – Pro Forma (a)	$ 2.74	$ 0.27	$ (1.59)

(a) The pro forma amounts are not representative of the effects on reported net income for future years.

Earnings Per Share (EPS)

Basic earnings (loss) per common share is calculated by dividing net earnings (loss) available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards. The effects of stock options have not been included in the fiscal 2002 diluted loss per common share calculation as their effect would have been antidilutive.

The calculation of our basic and diluted earnings (loss) per common share (EPS) is based on weighted average common shares shown in the table below:

	2004	2003	2002
		(in millions)	
Weighted Average Shares:			
Average Common Shares Outstanding	396	385	332
Assumed Conversion of Dilutive Stock Options (see Note 12)	-	-	-
Diluted Average Common Shares Outstanding	396	385	332

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share. Our basic and diluted EPS are the same in 2004, 2003 and 2002 since the effect on weighted average common shares outstanding is minimal.

Had we reported net income in fiscal 2002, incremental shares attributable to the assumed exercise of outstanding stock options would have increased diluted common shares outstanding by 398,000 shares.

Options to purchase 5.2 million, 5.6 million and 8.8 million shares of common stock were outstanding at December 31, 2004, 2003 and 2002, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the year-end market price of the common shares and, therefore, the effect would be antidilutive.

In addition, there is no effect on diluted earnings per share related to our equity units (issued in 2002) unless the market value of our common stock exceeds $49.08 per share. There were no dilutive effects from equity units at December 31, 2004, 2003 and 2002. If our common stock value exceeds $49.08 we would apply the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contracts are used to repurchase outstanding shares (see "Equity Units" section of Note 17).

Supplementary Information

	Year Ended December 31,		
	2004	2003	2002
Related Party Transactions		(in millions)	
AEP Consolidated Purchased Power – Ohio Valley Electric Corporation (44.2% owned by AEP)	$ 161	$ 147	$ 142
AEP Consolidated Other Revenues – barging and other transportation services – Ohio Valley Electric Corporation (44.2% owned by AEP)	14	9	-
Cash Flow Information			
Cash was paid (received) for:			
Interest (net of capitalized amounts)	755	741	792
Income Taxes	(107)	163	336
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	120	25	6
Assumption (Disposition) of Liabilities Related to Acquisitions/Divestitures	(67)	-	1
Increase in assets and liabilities resulting from:			
Consolidation of VIEs due to the adoption of FIN 46	-	547	-
Consolidation of merchant power generation facility	-	496	-

Power Projects

We own a 50% interest in a domestic unregulated power plant with a capacity of 450 MW located in Texas and an international power plant totaling 600 MW located in Mexico (see Note 10).

We account for investments in power projects that are 50% or less owned using the equity method and report them as Investments in Power and Distribution Projects on our Consolidated Balance Sheets (see "Eastex" section in Note 10). At December 31, 2004, the 50% owned domestic power project and international power investment are accounted for under the equity method and have unrelated third-party partners. The domestic project is a combined cycle gas turbine that provides steam to a host commercial customer and is considered a Qualifying Facility (QF) under PURPA. The international power investment is classified as a Foreign Utility Company (FUCO) under the Energy Policies Act of 1992.

Both the international and domestic power projects have project-level financing, which is nonrecourse to AEP. In addition, for the international project, AEP has guaranteed $57 million of letters of credit associated with the financing and a $10 million letter of credit for the benefit of the power purchaser under the power supply contract.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income (Loss).

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we thoroughly review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented during 2004 that we have determined relate to our operations.

FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

We implemented FASB Staff Position (FSP) FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," effective April 1, 2004, retroactive to January 1, 2004. The new disclosure standard provides authoritative guidance on the accounting for any effects of the Medicare prescription drug subsidy under the Act. It replaces the earlier FSP FAS 106-1, under which we previously elected to defer accounting for any effects of the Act until the FASB issued authoritative guidance on the accounting for the Medicare subsidy.

Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106's 10 percent corridor. See Note 11 for additional information related to the effects of implementation of FAS 106-2 on our postretirement benefit plans.

SFAS 123 (revised 2004) "Share-Based Payment" (SFAS 123R)

In December 2004, the FASB issued SFAS 123R, "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25. The statement is effective as of the first interim or annual period beginning after June 15, 2005, with early implementation permitted. A cumulative effect of a change in accounting principle is recorded for the effect of initially applying the statement.

We will implement SFAS 123R in the third quarter of 2005 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. We do not expect implementation of SFAS 123R to materially affect our results of operations, cash flows or financial condition.

SFAS 153 "Exchange of Nonmonetary Assets: an amendment of APB Opinion No. 29"

In December 2004, the FASB issued SFAS 153, "Exchange of Nonmonetary Assets: an amendment of APB Opinion No. 29" to eliminate the Opinion 29 exception to fair value for nonmonetary exchanges of similar productive assets and to replace it with a general exception for exchange transactions that do not have commercial substance. We expect to implement SFAS 153 prospectively, beginning July 1, 2005. We do not expect the effect to be material to our results of operations, cash flows or financial condition.

FIN 46 (revised December 2003)"Consolidation of Variable Interest Entities" and FIN 46 "Consolidation of Variable Interest Entities"

We implemented FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. FIN 46 interprets the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Due to the prospective application of FIN 46, we did not reclassify prior period amounts.

On July 1, 2003, we deconsolidated Caddis Partners, LLC (Caddis) and we also deconsolidated the trusts which hold mandatorily redeemable trust preferred securities (see “Minority Interest in Finance Subsidiary” and “Trust Preferred Securities” sections of Note 17).

Effective July 1, 2003, SWEPCo consolidated Sabine Mining Company (Sabine), a contract mining operation providing mining services to SWEPCo. Also, after consolidation, SWEPCo records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine’s revenues against SWEPCo’s fuel expenses. There is no cumulative effect of accounting change recorded as a result of the requirement to consolidate, and there was no change in net income due to the consolidation of Sabine.

Effective July 1, 2003, OPCo consolidated JMG, an entity formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG’s revenues against OPCo’s operating lease expenses. There is no cumulative effect of accounting change recorded as a result of our requirement to consolidate JMG, and there was no change in net income due to the consolidation of JMG (see “Gavin Scrubber Financing Agreement” section of Note 16).

In December 2003, the FASB issued FIN 46 (revised December 2003) (FIN 46R) which replaces FIN 46. We implemented FIN 46R effective March 31, 2004 with no material impact to our financial statements.

EITF Issue 03-13 “Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations”

This issue developed a model for evaluating which cash flows are to be considered in determining whether cash flows have been or will be eliminated and what types of continuing involvement constitute significant continuing involvement when determining whether to report Discontinued Operations. We will apply this issue to components that are disposed of or classified as held for sale in periods beginning after December 15, 2004.

FASB Staff Position 109-1 “Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Activities Provided by the American Jobs Creation Act of 2004”

On October 22, 2004, the American Jobs Creation Act of 2004 (Act) was signed into law. The Act included tax relief for domestic manufacturers (including the production, but not the delivery of electricity) by providing a tax deduction up to 9 percent (when fully phased-in in 2010) on a percentage of “qualified production activities income.” Beginning in 2005 and for 2006, the deduction is 3 percent of qualified production activities income. The deduction increases to 6 percent for 2007, 2008 and 2009. The FASB staff has indicated that this tax relief should be treated as a special deduction and not as a tax rate reduction. While the U.S. Treasury has issued general guidance on the calculation of the deduction, this guidance lacks clarity as to determination of qualified production activities income as it relates to utility operations. We believe that the special deduction for 2005 and 2006 will not materially affect our results of operations, cash flows, or financial condition.

Future Accounting Changes

The FASB’s standard-setting process is ongoing and until new standards have been finalized and issued by FASB, 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 accounting for uncertain tax positions, asset retirement obligations, fair value measurements, business combinations, revenue recognition, pension plans, liabilities and equity, earnings per share calculations, accounting changes and related tax impacts as applicable. We also expect to see more FASB projects as a result of their desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

EXTRAORDINARY ITEM

In the fourth quarter of 2004, as part of its True-up Proceeding, TCC made net adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset related to its transition to retail competition. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis, including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCC's stranded generation plant costs regulatory asset was reduced by $238 million based on a PUCT adjustment in the CenterPoint Order (see "Wholesale Capacity Auction True-up" section of Note 6). These net adjustments were recorded as an extraordinary item in accordance with SFAS 101 and are reflected in our Consolidated Statements of Operations as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10, "Accounting for Contracts Included in Energy Trading and Risk Management Activities," and related interpretive guidance. We recorded a $49 million after tax charge against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in the first quarter of 2003 ($13 million in Utility Operations, $22 million in Investments – Gas Operations and $14 million in Investments – UK Operations segments). These amounts are recognized as the positions settle.

Asset Retirement Obligations

In the first quarter of 2003, we recorded $242 million of after tax income as a cumulative effect of accounting change for Asset Retirement Obligations in accordance with SFAS 143 ($249 million after tax income in Utility Operations and $7 million after tax loss in Investments-UK Operations segment).

Goodwill and Other Intangible Assets

SFAS 142, "Goodwill and Other Intangible Assets," requires that goodwill and intangible assets with indefinite useful lives no longer be amortized and be tested annually for impairment. The implementation of SFAS 142 in 2002 resulted in a $350 million net transitional loss for our U.K. and Australian operations (included in the Investments – Other segment) and is reported in our Consolidated Statements of Operations as a cumulative effect of accounting change (see Note 3).

See table below for details of the Cumulative Effect of Accounting Changes:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
Accounting for Risk Management Contracts (EITF 02-3)	$ -	$ (49)(a)	$ -
Asset Retirement Obligations (SFAS 143)	-	242 (b)	-
Goodwill and Other Intangible Assets (SFAS 142)	-	-	(350)(c)
Total	$ -	$ 193	$ (350)

(a) net of tax of $19 million
(b) net of tax of $157 million
(c) net of tax of $0

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2004 and 2003 by operating segment are:

	Utility Operations	Investments Gas Operations	Investments UK Operations	Investments Other	AEP Consolidated
			(in millions)		
Balance at January 1, 2003	$ 37.1	$ 306.3	$ 11.2	$ 41.4	$ 396.0
Impairment losses (a)	-	(291.4)	(12.2)	-	(303.6)
Assets Held for Sale, Net (b)	-	(14.9)	-	-	(14.9)
Foreign currency exchange rate changes	-	-	1.0	-	1.0
Balance at December 31, 2003	$ 37.1	$ -	$ -	$ 41.4	$ 78.5
Balance at January 1, 2004	$ 37.1	$ -	$ -	$ 41.4	$ 78.5
Goodwill written off related to sale of Numanco	-	-	-	(2.6)	(2.6)
Balance at December 31, 2004	$ 37.1	$ -	$ -	$ 38.8	$ 75.9

(a) Impairment Losses: (see Note 10)

2003
Gas Operations
In the fourth quarter of 2003, we prepared our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. As a result of the tests, we recognized a $162.5 million goodwill impairment loss related to HPL ($150.4 million) and AEPES ($12.1 million).

Also during 2003, we recognized a goodwill impairment loss of $128.9 million related to Jefferson Island.

UK Operations
In 2003, we recognized a goodwill impairment loss of $12.2 million related to UK Coal Trading.

2004
In the fourth quarter of 2004, we prepared 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.

(b) On our Consolidated Balance Sheets, amounts related to entities classified as held for sale are excluded from Goodwill and are reported within Assets of Discontinued Operations and Held for Sale until they are sold (see Note 10). The following entities were classified as held for sale and had goodwill impairments for the year ended December 31, 2003:

- Jefferson Island (Investments – Gas Operations segment) – $14.4 million balance in goodwill at December 31, 2003.
- LIG Chemical (Investments – Gas Operations segment) – $0.5 million balance in goodwill at December 31, 2003.

OTHER INTANGIBLE ASSETS

Acquired intangible assets subject to amortization are $29.7 million at December 31, 2004 and $34.1 million at December 31, 2003, net of accumulated amortization and are included in Other Noncurrent Assets on the Consolidated Balance Sheets. The gross carrying amount, accumulated amortization and amortization life by major asset class are:

		December 31, 2004		December 31, 2003	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Software acquired (a)	3	$ -	$ -	$ 0.5	$ 0.3
Patent	5	0.1	0.1	0.1	-
Easements	10	2.2	0.5	2.2	0.3
Trade name and administration of contracts	7	2.4	0.9	2.4	0.9
Purchased technology	10	10.9	3.2	10.9	2.2
Advanced royalties	10	29.4	10.6	29.4	7.7
Total		$ 45.0	$ 15.3	$ 45.5	$ 11.4

(a) This asset related to U.K. Generation Plants and was sold during the third quarter of 2004.

Amortization of intangible assets was $4 million, $5 million and $4 million for 2004, 2003 and 2002, respectively. Our estimated total amortization is $5 million for each year 2005 through 2007, $4 million for 2008 through 2010 and $3 million in 2011.

4. RATE MATTERS

In certain jurisdictions, we have agreed to base rate or fuel recovery limitations usually under terms of settlement agreements. See Note 5 for a discussion of those terms related to the Nuclear Plant Restart and the Merger with CSW.

TNC Fuel Reconciliations

In 2002, TNC filed with the PUCT to reconcile fuel costs and defer the unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in its True-up Proceeding. As a result of the introduction of customer choice on January 1, 2002, this fuel reconciliation for the period from July 2000 through December 2001 is the final fuel reconciliation for TNC's ERCOT service territory.

Through 2004, TNC provided $30 million for various disallowances recommended by the ALJ and accepted by the PUCT in open session of which $20 million was recorded in 2003 and $10 million in 2004. On October 18, 2004, the PUCT issued a final order which concluded that the over-recovery balance was $4 million. TNC has fully provided for the PUCT's final order in this proceeding. TNC has sought declaratory and injunctive relief in Federal District Court for $8 million of its provision resulting from the PUCT's rejection of TNC's application of a FERC-approved tariff on the basis that the interpretation of the tariff is within the exclusive jurisdiction of the FERC and not the PUCT. TNC has also appealed various other issues to state District Court in Travis County for which it has provided $22 million. Another party has also filed a state court appeal. TNC will pursue vigorously these proceedings but at present cannot predict their outcome.

In February 2002, TNC received a final PUCT order in a previous fuel reconciliation covering the period July 1997 through June 2000 and reflected the order in its financial statements. In September 2004, that decision was affirmed by the Third Court of Appeals. No appeal was filed with the Supreme Court of Texas.

TCC Fuel Reconciliation

In 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in its True-up Proceeding. This reconciliation covers the period from July 1998 through December 2001.

On February 3, 2004, the ALJ issued a PFD recommending that the PUCT disallow $140 million of eligible fuel costs. In May 2004, the PUCT accepted most of the ALJ's recommendations in the TCC case, however, the PUCT rejected the ALJ's recommendation to impute capacity to certain energy-only purchased power contracts and remanded the issue to the ALJ to determine if any energy-only purchased power contracts during the reconciliation period include a capacity component that is not recoverable in fuel revenues. In testimony filed in the remand proceeding, TCC asserted that its energy-only purchased power contracts do not include any capacity component. Intervenors, including the Office of Public Utility Counsel (OPC), have filed testimony recommending that $15 million to $30 million of TCC's purchased power costs reflect capacity costs which are not recoverable in the fuel reconciliation. The ALJ issued a report on January 13, 2005 on the imputed capacity remand recommending that specified energy-only purchased power contracts include a capacity component with a value of $2 million. At its February 24, 2005 open meeting, the PUCT reviewed the ALJ report and also ruled that specific energy-only purchased power contracts include a capacity component of $2 million. As a result of the PUCT's acceptance of most of the ALJ's recommendations in TCC's case and the PUCT's rejection in the TNC case of our interpretation of its FERC tariff, TCC has recorded provisions totaling $143 million, with $81 million provided in 2003 and $62 million in 2004. The over-recovery balance and the provisions for probable disallowances totaled $212 million including interest at December 31, 2004.

Management believes they have materially provided for probable to-date disallowances in TCC's final fuel reconciliation pending receipt of a final order. A final order has not yet been issued in TCC's final fuel reconciliation. An order from the PUCT, disallowing amounts in excess of the established provision, could have a material adverse effect on future results of operations and cash flows. We will continue to challenge adverse decisions vigorously, including appeals and challenges in Federal Court if necessary. Additional information regarding the True-up Proceeding for TCC can be found in Note 6.

SWEPCo Texas Fuel Reconciliation

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in SPP. This reconciliation covers the period from January 2000 through December 2002. During the reconciliation period, SWEPCo incurred $435 million of Texas retail eligible fuel expense. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation proceeding. The settlement provides for a disallowance in fuel costs of $8 million which was recorded in December 2003. In April 2004, the PUCT approved the settlement.

SWEPCo Fuel Factor Increase

On November 5, 2004, SWEPCo filed a petition with the PUCT to increase its annual fixed fuel factor by $29 million. SWEPCo and the various parties to the proceedings reached a settlement effective January 31, 2005 that increases its annual fixed fuel factor revenues by approximately $25 million or approximately 18% over the amount that would be collected by the fuel factors currently in effect. The settlement agreement was approved by the PUCT on January 31, 2005. Actual fuel costs will be subject to review and approval in a future fuel reconciliation.

SWEPCo Louisiana Fuel Audit

The Louisiana Public Service Commission (LPSC) is performing an audit of SWEPCo's historical fuel costs. In addition, five SWEPCo customers filed a suit in the Caddo Parish District Court in January 2003 and filed a complaint with the LPSC. The customers claim that SWEPCo has overcharged them for fuel costs since 1975. The LPSC consolidated the customer complaints and audit. In testimony filed in this matter, the LPSC Staff recommended refunds of approximately $5 million. Subsequently, surrebuttal testimony filed by the LPSC Staff recognized that SWEPCo's costs were reasonable and that most costs could be recovered through the fuel adjustment clause pending LPSC approval. While initial indications from the LPSC Staff surrebuttal testimony would not indicate a material disallowance, management cannot predict the ultimate outcome in this proceeding. If the LPSC or the Court does not agree with LPSC Staff recommendations, it could have an adverse effect on future results of operations and cash flows.

PSO Fuel and Purchased Power

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed testimony in February 2004.

An intervenor and the OCC Staff filed testimony in April 2004. The intervenor suggested that $9 million related to the 2002 reallocation not be recovered from customers. The Attorney General of Oklahoma also filed a statement of position, indicating allocated off-system sales margins between and among AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and, if corrected, could more than offset the $44 million 2002 reallocation under-recovery. The intervenor and the OCC Staff also argued that off-system sales margins were allocated incorrectly. The intervenors' reallocation of such margins would reduce PSO's recoverable fuel costs by $7 million for 2000 and $11 million for 2001, while under the OCC Staff method, the reduction for 2001 would be $9 million. The intervenor and the OCC Staff also recommended recalculation of PSO's fuel costs for years subsequent to 2001 using the same revised methods. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were under the jurisdiction of the OCC because they relate to FERC-approved allocation agreements. As a result, the ALJ ordered that the parties brief the jurisdictional issue. After reviewing the briefs, the ALJ recommended that the OCC lacks authority to examine whether PSO deviated from the FERC allocation methodology and that any such complaints should be addressed at the FERC. In January 2005, the OCC conducted a hearing on the jurisdictional matter and a ruling is expected in the near future. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

Virginia Fuel Factor Filing

On October 29, 2004, APCo filed a request with the Virginia State Corporation Commission (Virginia SCC) to increase its fuel factor effective January 1, 2005. The requested factor is estimated to increase revenues by approximately $19 million on an annual basis. This increase reflects a continuing rise in the projected cost of coal in 2005. By order dated November 16, 2004, the Virginia SCC approved APCo's request on an interim basis, pending a hearing to be held in February 2005. The Virginia SCC issued an order on February 11, 2005 approving the continuation of the January 1, 2005 interim fuel factor, which is subject to final audit. This fuel factor adjustment will increase cash flows without impacting results of operations as any over-recovery or under-recovery of fuel cost would be deferred as a regulatory liability or a regulatory asset.

Indiana Fuel Order

On August 27, 2003, the IURC ordered certain parties to negotiate the appropriate action on I&M's fuel cost recovery beginning March 1, 2004, following the February 2004 expiration of a fixed fuel adjustment charge that capped fuel recoveries (fixed pursuant to a prior settlement of Cook Nuclear Plant outage issues). I&M agreed, contingent on AEP implementing corporate separation for some of its subsidiaries, to a fixed fuel adjustment charge beginning March 2004 and continuing through December 2007. Although we have not corporately separated, certain parties believe the fixed fuel adjustment charge should continue beyond February 2004. Negotiations to resolve this issue are ongoing. The IURC ordered that the fixed fuel adjustment charge remain in place, on an interim basis, through April 2004.

In April 2004, the IURC issued an order that extended the interim fuel factor from May through September 2004, subject to true-up to actual fuel costs following the resolution of the issue regarding the corporate separation agreement. The IURC also reopened the corporate separation docket to investigate issues related to the corporate separation agreement. In July 2004, we filed for approval of a fuel factor for the period October 2004 through March 2005. On September 22, 2004, the IURC issued another order extending the interim fuel factor from October 2004 through March 2005, subject to true-up upon resolution of the corporate separation issues. At December 31, 2004, I&M has under-recovered its fuel costs by $2 million. If I&M's net recovery should remain an under-recovery and if I&M would be required to continue to bill the existing fixed fuel adjustment factor that caps fuel revenues, future results of operations and cash flows would be adversely affected.

Michigan 2004 Fuel Recovery Plan

On September 30, 2003, I&M filed its 2004 Power Supply Cost Recovery (PSCR) Plan with the Michigan Public Service Commission (MPSC) requesting fuel and power supply recovery factors for 2004, which were implemented pursuant to statute effective with January 2004 billings. A public hearing was held on March 10, 2004. On June 4, 2004, the ALJ recommended that net SO_2 and NO_x credits be excluded from the fuel recovery mechanism. I&M filed its exceptions in June 2004. If the ALJ's recommendation is adopted by the MPSC and in a future period SO_2 and NO_x are a net cost, it would adversely affect results of operations and cash flows. On September 30, 2004, I&M filed its 2005 PSCR Plan, which reflects net credits of approximately $5 million.

TCC Rate Case

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCC's proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%.

In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCC's requested $67 million annual rate increase. Their recommendations ranged from a decrease in annual existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. Hearings were held in March 2004. In May 2004, TCC agreed to a nonunanimous settlement on cost of capital including capital structure and return on equity with all but two parties in the proceeding. TCC agreed that the return on equity should be established at 10.125% based upon a capital structure with 40% equity resulting in a weighted cost of capital of 7.475%. The settlement and other agreed adjustments reduced TCC's rate request from $67 million to $41 million.

On July 1, 2004, the ALJs who heard the case issued their recommendations which included a recommendation to approve the cost of capital settlement. The ALJs recommended that an issue related to the allocation of consolidated tax savings to the transmission and distribution utility be remanded back to the ALJs for additional evidence. On July 15, 2004, the PUCT remanded this issue to the ALJs. On August 19, 2004, in a separate ruling, the PUCT remanded six other issues to the ALJs requesting revisions to clarify and support the recommendations in the PFD.

The PUCT ordered TCC to calculate its revenue requirements based upon the recommendations of the ALJs. On July 21, 2004, TCC filed its revenue requirements based upon the recommendations of the ALJs. According to TCC's calculations, the ALJs' recommendations would reduce TCC's annual existing rates between $33 million and $43 million depending on the final resolution of the amount of consolidated tax savings.

On November 16, 2004, the ALJs issued their PFD on remand, increasing their recommended annual rate reduction to a range of $51 million to $78 million, depending on the amount disallowed related to affiliated AEPSC billed expenses. At the January 13, 2005 and January 27, 2005 open meetings, the Commissioners considered a number of issues, but deferred resolution of the affiliated AEPSC billed expenses issue, among other less significant issues, until after additional hearings scheduled for March 2005. Adjusted for the decisions announced by the Commissioners in January 2005, the ALJs' disallowance would yield an annual rate reduction of a range of $48 million to $75 million. If TCC were to prevail on the affiliated expenses issue and all remaining issues, the result would be an annual rate increase of $6 million. When issued, the PUCT order will affect revenues prospectively. An order reducing TCC's rates could have a material adverse effect on future results of operations and cash flows.

TCC and TNC ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the OPC and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. On June 25, 2003, the District Court ruled in both appeals. The Court ruled in the Mutual Energy WTU case that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately \$2.7 million for Mutual Energy WTU. The Court upheld the initial PTB orders on all other issues. In the Mutual Energy CPL proceeding, the Court also ruled that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. The District Court decision was appealed to the Third Court of Appeals by Mutual Energy CPL, Mutual Energy WTU and other parties. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the District Court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in the years 2002 through 2004 resulting in an adverse effect on future results of operations and cash flows.

TCC Unbundled Cost of Service (UCOS) Appeal

The UCOS proceeding established the unbundled regulated wires rates to be effective when retail electric competition began. TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. Regulated delivery charges include the retail transmission and distribution charge and, among other items, a nuclear decommissioning fund charge, a municipal franchise fee, a system benefit fund fee, a transition charge associated with securitization of regulatory assets and a credit for excess earnings. Certain PUCT rulings, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, the regulatory treatment of nuclear insurance and the distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to nonbypassable transmission and distribution rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. The distribution rate credit began in January 2002. This decision could potentially affect the PTB rates charged by Mutual Energy CPL and could result in a refund to certain of its customers. Mutual Energy CPL was a subsidiary of AEP until December 23, 2002 when it was sold. Management estimates that the adverse effect of a decision to reduce the PTB rates for the period prior to the sale is approximately \$11 million pretax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

SWEPCo Louisiana Compliance Filing

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid-2005. In April 2004, SWEPCo filed updated financial information with a test year ending December 31, 2003 as required by the LPSC. Both filings indicated that SWEPCo's current rates should not be reduced. Subsequently, direct testimony was filed on behalf of the LPSC recommending a \$15 million reduction in SWEPCo's Louisiana jurisdictional base rates. SWEPCo's rebuttal testimony was filed on January 16, 2005. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ordered in the future, it would adversely impact future results of operations and cash flows.

PSO Rate Review

In February 2003, the OCC Staff filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003 and June 2004, PSO filed financial information and supporting testimony in response to the OCC Staff's request. PSO's initial response indicated that its annual revenues were $36 million less than costs. The June 2004 filing updated PSO's request and indicated a $41 million revenue deficiency. As a result, PSO sought OCC approval to increase its base rates by that amount, which is a 3.9% increase over PSO's existing revenues.

In August 2004, PSO filed a motion to amend the timeline to consider new service quality and reliability requirements, which took effect on July 1, 2004. Also in August 2004, the OCC approved a revised schedule. In October 2004, PSO filed supplemental information requesting consideration of approximately $55 million of additional annual operations and maintenance expenses and annual capital costs to enhance system reliability. In November 2004, PSO filed a plan with the OCC seeking interim rate relief to fund a portion of the costs to meet the new state service quality and reliability requirements pending the outcome of the current case. In the filing, PSO sought interim approval to collect annual incremental tree trimming costs of approximately $23 million from its customers. Intervenors and the OCC Staff filed testimony recommending that the interim rate relief requested by PSO be modified or denied. The OCC issued an order on PSO's interim request in January 2005, which allows PSO to recover up to an additional $12 million annually for reliability activities beginning in December 2004. Expenses exceeding that amount and the amount currently included in base rates will be considered in the base rate case.

The OCC Staff and intervenors filed testimony regarding their recommendations on revenue requirement, fuel procurement, resource planning and vegetation management in January 2005. Their recommendations ranged from a decrease in annual existing rates between $15 million and $36 million. In addition, one party recommended that the OCC require PSO file additional information regarding its natural gas purchasing practices. In the absence of such a filing, this party suggested that $30 million of PSO's natural gas costs not be recovered from customers because it failed to implement a procurement strategy that, according to this party, would have resulted in lower natural gas costs. OCC Staff and intervenors recommended a return on common equity ranging from 9.3% to 10.11%. PSO's rebuttal testimony was filed in February 2005, and that testimony reflects a number of adjustments to PSO's June 2004 updated filing. These adjustments result in a decrease of PSO's revenue deficiency in this case from $41 million to $28 million, although approximately $9 million of that decrease are items that would be recovered through the fuel adjustment clause rather than through base rates. Hearings are scheduled to begin in March 2005, and a final decision is not expected any earlier than the second quarter of 2005. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

PSO Lawton Power Supply Agreement

On November 26, 2003, pursuant to an application by Lawton Cogeneration Incorporated seeking avoided cost payments and approval of a power supply agreement, OCC issued an order approving payment of avoided costs and a Power Supply Agreement (Agreement). Among other things, in the order, the OCC did not approve PSO's recovery of the costs of the Agreement.

In December 2003, PSO filed an appeal of the OCC's order with the Oklahoma Supreme Court. In the appeal, PSO maintains that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. Should the OCC's order be upheld by the Supreme Court, PSO anticipates full recovery of the costs of the Agreement. However, if the OCC was to deny recovery of a material amount, it would adversely affect future results of operations and cash flows.

Upon resolution of this issue, management would review any transaction for the effect, if any, on the balance sheet relating to lease and FIN 46R accounting.

KPCo Environmental Surcharge Filing

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately $21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million became effective in May 2003 and an additional $16.2 million became effective in July 2003. The recovery of such amounts is intended to offset KPCo's cost of compliance with the CAA.

RTO Formation/Integration

Based on FERC approvals in response to nonaffiliated companies' requests to defer RTO formation costs, the AEP East companies deferred costs incurred under FERC orders to form a new RTO (the Alliance RTO) or subsequently to join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both Alliance RTO formation costs and PJM integration costs, including the deferral of a carrying charge thereon. The AEP East companies have deferred approximately $37 million of RTO formation and integration costs and related carrying charges through December 31, 2004.

In its July 2003 order, the FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the OATT to be charged by PJM. Management believes that the FERC will grant permission for prudently incurred deferred RTO formation/integration costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of the AEP East companies' portion of the OATT as these companies file rate cases. As of December 31, 2004, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo and OPCo until January 1, 2006.

In August 2004, we filed an application with the FERC dividing the RTO formation/integration costs between PJM-incurred integration costs billed to us including related carrying charges, and all other RTO formation/integration costs. We intend to file with the FERC to request that deferred PJM-incurred integration costs billed to us be recovered from all PJM customers. We anticipate the other RTO formation/integration costs will be recovered through transmission rates in the AEP East zone. The AEP East companies will be responsible for paying most of the amount allocated by the FERC to the AEP East zone since it will be attributable to their internal load. In our August 2004 application, we requested permission to amortize over 15 years beginning January 1, 2005 the cost to be billed within the AEP East zone which represents approximately one-half of the total deferred RTO formation/integration costs. We also requested to begin amortizing the deferred PJM-billed integration costs on January 1, 2005, but we did not propose an amortization period in the application. The FERC has not ruled on our application.

The AEP East companies integrated into PJM on October 1, 2004. We intend to file a joint request with other new PJM members to recover approximately one-half of the deferred RTO formation/integration costs (i.e. the PJM-incurred integration expenses billed to AEP) through a new charge in the PJM OATT that would apply to all loads and generation in the PJM region during a 10-year period beginning in May 2005. The AEP East companies will expense their portion of the PJM-incurred integration costs billed by PJM under the new charge. We will amortize the remaining portion of our RTO formation/integration costs over the period to be approved by the FERC and seek recovery of such costs in the retail rates for each of the AEP East companies' state jurisdictions. Management believes that it is probable that the FERC will approve recovery of the PJM-incurred integration costs to be billed to us through the PJM OATT and that the FERC will grant a long enough amortization period to allow for the opportunity for recovery of the non-PJM incurred RTO formation/integration costs in the AEP East retail jurisdictions. If the FERC ultimately decides not to approve an amortization period that would provide us with the opportunity to include such costs in future retail rate filings or the FERC or the state commissions deny recovery of our share of these deferred costs, future results of operations and cash flows could be adversely affected.

FERC Order on Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the Midwest Independent System Operator (MISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and expanded PJM regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners including AEP East companies under the RTOs' revenue distribution protocols.

In November 2003, the FERC issued an order finding that the T&O rates of the former Alliance RTO participants, including AEP, should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and former Alliance RTO participants to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004. The FERC is expected to implement a new rate design after the two-year period. In April 2004, the FERC approved a settlement that delayed elimination of T&O rates and the implementation of SECA replacement rates until December 1, 2004 when the FERC would implement a new rate design.

On November 18, 2004, the FERC conditionally approved a license plate rate design to eliminate rate pancaking for transmission service within the Combined Footprint and adopted its previously approved SECA transition rate methodology to mitigate the effects of the elimination of T&O rates effective December 1, 2004. Under license plate rates, customers serving load within a RTO pay transmission service rates based on the embedded cost of the transmission facilities in the local pricing zone where the load being served is located. The use of license plate rates would shift costs that we previously recovered from our T&O service customers to mainly AEP's native load customers within the AEP East pricing zone. The SECA transition rates will remain in effect through March 31, 2006. The SECA rates are designed to mitigate the loss of revenues due to the elimination of T&O rates.

The SECA rates became effective December 1, 2004. Billing statements from PJM for December 2004 did not reflect any credits to AEP for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP accrued $11 million in December 2004 for SECA revenues. On January 7, 2005, AEP and Exelon filed joint comments and protests with the FERC including a request that FERC direct PJM and MISO to comply with the FERC decision and collect all SECA revenues due with interest charges for all late-billed amounts. On February 10, 2005, the FERC issued an order indicating that the SECA transition rates would be subject to refund or surcharge and set for hearing all remaining aspects of the compliance filings to the November 18 order, including our request that the FERC direct PJM and MISO begin billing and collecting the SECA transition rates.

The AEP East companies received approximately $196 million of T&O rate revenues within the PJM/MISO Expanded Footprint for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA charges was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, or if any increase in the AEP East companies' transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Hold Harmless Proceeding

In its July 2002 order conditionally accepting our choice to join PJM, the FERC directed us, ComEd, MISO and PJM to propose a solution that would effectively hold harmless the utilities in Michigan and Wisconsin from any adverse effects associated with loop flows or congestion resulting from us and ComEd joining PJM instead of MISO. In December 2003, AEP and ComEd jointly filed a hold-harmless proposal, which was rejected by the FERC in March 2004 without prejudice to the filing of a new proposal.

In July 2004, AEP and PJM filed jointly with the FERC a new hold-harmless proposal that was nearly identical to a proposal filed jointly by ComEd and PJM in April 2004. In September 2004, the FERC accepted and suspended the new proposal that became effective October 1, 2004, subject to refund and to the outcome of a hearing on the appropriate compensation, if any, to the Michigan and Wisconsin utilities. A hearing is scheduled for April 2005.

The proposed hold-harmless agreement as filed by PJM and us specifies that the term of the agreement commences on October 1, 2004 and terminates when the FERC determines that effective internalization of congestion and loop flows is accomplished. The Michigan and Wisconsin utilities have presented studies that show estimated adverse effects to utilities in the two states in the range of $60 to $70 million over the term of the agreement for ComEd and AEP. The recent supplemental filing by the Michigan companies shows estimated adverse effects to utilities in Michigan of up to $50 million over the term of agreement. AEP and ComEd have presented studies that show no adverse effects to the Michigan and Wisconsin utilities. ComEd has separately settled this issue with the Michigan and Wisconsin utilities for a one time total payment of approximately $5 million, which was approved by the FERC. On December 27, 2004, AEP and the Wisconsin utilities jointly filed a settlement that resolves all hold-harmless issues for a one-time payment of $250,000 which is pending approval before the FERC.

At this time, management is unable to predict the outcome of this proceeding. AEP will support vigorously its positions before the FERC. No provision has been established. If the FERC ultimately approves a significant hold-harmless payment to the Michigan and Wisconsin utilities, it would adversely impact results of operations and cash flows.

FERC Market Power Mitigation

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. These two screening tests include a "pivotal supplier" test which determines if the market load can be fully served by alternative suppliers and a "market share" test which compares the amount of surplus generation at the time of the applicant's minimum load. In July 2004, the FERC issued an order on rehearing, affirming its conclusions in the April order and directing AEP and two nonaffiliated utilities to file generation market power analyses within 30 days. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way.

On August 9, 2004, as amended on September 16, 2004 and November 19, 2004, AEP submitted its generation market power screens in compliance with the FERC's orders. The analysis focused on the three major areas in which AEP serves load and owns generation resources -- ECAR, SPP and ERCOT, and the "first tier" control areas for each of those areas.

The pivotal supplier and market share screen analyses that AEP filed demonstrated that AEP does not possess market power in any of the control areas to which it is directly connected (first-tier markets). AEP passed both screening tests in all of its "first tier" markets. In its three "home" control areas, AEP passed the pivotal supplier test. AEP, as part of PJM, also passes the market share screen for the PJM destination market. AEP also passed the market share screen for ERCOT. AEP did not pass the market share screen as designed by the FERC for the SPP control area.

In a December 17, 2004 order, FERC affirmed our conclusions that we passed both market power screen tests in all areas except SPP. Because AEP did not pass the market share screen in SPP, FERC initiated proceedings under Section 206 of the Federal Power Act in which AEP is rebuttably presumed to possess market power in SPP. Consequently, our revenues from sales in SPP at market based rates after March 6, 2005 will be collected subject to refund to the extent that prices are ultimately found not to be just and reasonable. On February 15, 2005, although we continue to believe we do not possess market power in SPP, we filed a response and proposed tariff changes to address FERC's market-power concerns. The proposed tariff change would apply to sales that sink within the service territories of PSO, SWEPCo and TNC within the SPP that encompass the AEP-SPP control area, and make such sales subject to cost-based rate caps. We have requested the amended tariffs to become effective March 6, 2005.

In addition to FERC market monitoring, we are subject to market monitoring oversight by the RTOs in which we are a member, including PJM and SPP. These market monitors have authority for oversight and market power mitigation.

Management believes that we are unable to exercise market power in any region. At this time the impact on future wholesale power revenues, results of operations and cash flows of the FERC's and PJM's market power analysis cannot be determined.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2004	December 31, 2003	Future Recovery/Refund Period
	(in millions)		
Regulatory Assets:			
Income Tax Related Regulatory Assets, Net	$ 796	$ 728	Various Periods (a)
Transition Regulatory Assets	407	529	Up to 6 Years (a)
Designated for Securitization	1,361	1,289	(b)
Texas Wholesale Capacity Auction True-up	560	480	(c)
Unamortized Loss on Reacquired Debt	116	116	Up to 39 Years (d)
Cook Nuclear Plant Refueling Outage Levelization	44	57	(e)
Other	317	383	Various Periods (f)
Total Regulatory Assets	$ 3,601	$ 3,582	
Regulatory Liabilities and Deferred Investment Tax Credits:			
Asset Removal Costs	$ 1,290	$ 1,233	(g)
Deferred Investment Tax Credits	393	422	Up to 25 Years (a)
Excess ARO for Nuclear Decommissioning Liability	245	216	(h)
Over-recovery of Texas Fuel Costs	216	150	(c)
Deferred Over-recovered Fuel Costs	71	63	(a)
Texas Retail Clawback	75	57	(c)
Other	250	254	Various Periods (f)
Total Regulatory Liabilities	$ 2,540	$ 2,395	

(a) Amount does not earn a return.
(b) Amount includes a carrying cost, will be included in TCC's True-up Proceeding and is designated for possible securitization. The cost of the securitization bonds would be recovered over a time period to be determined in a future PUCT proceeding.
(c) See "Texas Restructuring" and "Carrying Costs on Net-True-up Regulatory Assets" sections of Note 6 for discussion of carrying costs. Amounts will be included in TCC's and TNC's true-up proceedings for future recovery/refund over a time period to be determined in a future PUCT proceeding.
(d) Amount effectively earns a return.
(e) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage and does not earn a return.
(f) Includes items both earning and not earning a return.
(g) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.
(h) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. This amount earns a return, accrues monthly, and will be paid when the nuclear plant is decommissioned.

Texas Restructuring Related Regulatory Assets and Liabilities

Regulatory Assets Designated for Securitization, Texas Wholesale Capacity Auction True-up regulatory assets, Over-recovery of Fuel Costs and Texas Retail Clawback regulatory liabilities are not currently being recovered from or returned to ratepayers. Management believes that the laws and regulations established in Texas for industry restructuring provide for the recovery from ratepayers of these net amounts. These amounts require approval of the PUCT in a future True-up Proceeding. See Note 6 for a complete discussion of our plans to seek recovery of these regulatory assets, net of regulatory liabilities.

Nuclear Plant Restart

I&M completed the restart of both units of the Cook Plant in 2000. Settlement agreements in the Indiana and Michigan retail jurisdictions that addressed recovery of Cook Plant related outage restart costs were approved in 1999 by the Indiana Utility Regulatory Commission and Michigan Public Service Commission.

The amount of deferrals amortized to maintenance and other operation expenses under the settlement agreements were $40 million in both 2003 and 2002. The Nuclear Plant Restart regulatory asset was fully amortized as of December 31, 2004 and 2003. Also, pursuant to the settlement agreements, accrued fuel-related revenues of approximately $37 million in 2003 and $38 million in 2002 were amortized as a reduction of revenues. The amortization of amounts deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected results of operations through December 31, 2003 when the amortization period ended.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. The following table summarizes significant merger-related agreements:

Summary of key provisions of Merger Rate Agreements:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	Rate reduction of $221 million over 6 years.
Indiana – I&M	Rate reduction of $67 million over 8 years.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years.
Oklahoma – PSO	Rate reductions of approximately $28 million over 5 years.
Arkansas – SWEPCo	Rate reductions of $6 million over 5 years.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years and a base rate cap until June 2005.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

See "Merger Litigation" section of Note 7 for information on a court decision concerning the merger.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

With the passage of restructuring legislation, six of our eleven electric utility companies (CSPCo, I&M, APCo, OPCo, TCC and TNC) are in various stages of transitioning to customer choice and/or market pricing for the supply of electricity in four of the eleven state retail jurisdictions (Ohio, Texas, Michigan and Virginia) in which the AEP domestic electric utility companies operate. The following paragraphs discuss significant events related to industry restructuring in those states.

OHIO RESTRUCTURING

The Ohio Electric Restructuring Act of 1999 (Ohio Act) provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005. The Public Utilities Commission of Ohio (PUCO) may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utility's certified territory or that there is a twenty percent switching rate of the incumbent utility's load by customer class. Following the MDP, retail customers will receive cost-based regulated distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates.

On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rules provide for a Market Based Standard Service Offer (MBSSO) which would be a variable rate based on transparent forward market, daily market, and/or hourly market prices. The rules also require a fixed-rate Competitive Bidding Process (CBP) for residential and small nonresidential customers and permits a fixed-rate CBP for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the MBSSO and the CBP. Customers who make no choice will be served pursuant to the CBP. The rules also required that electric distribution utilities file an application for MBSSO and CBP by July 1, 2004. CSPCo and OPCo were granted a waiver from making the required MBSSO/CBP filing, pending the outcome of a rate stabilization plan they filed with the PUCO in February 2004. As of December 31, 2004, none of OPCo's customers have elected to choose an alternate power supplier and only a modest number of CSPCo's small commercial customers has switched suppliers. This is believed to be due to CSPCo's and OPCo's rates being below market.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed rate stabilization plans with the PUCO addressing prices for the three-year period following the end of the MDP, January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. On January 26, 2005, the PUCO approved the plans with some modifications.

The approved plans include annual fixed increases in the generation component of all customers' bills (3% a year for CSPCo and 7% a year for OPCo) in 2006, 2007 and 2008. The plan also includes the opportunity to annually request an additional increase in supply prices averaging up to 4% per year for each company to recover certain new governmentally-mandated increased expenditures set out in the approved plan. The plans maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level in effect on December 31, 2005. Such rates could be adjusted with PUCO approval for specified reasons. Transmission charges could also be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion and ancillary services. The approved plans provide for the continued amortization and recovery of stranded transition generation-related regulatory assets. The plans, as modified by the PUCO, require CSPCo and OPCo to allot a combined total of $14 million of previously provided for unspent shopping incentives for the benefit of their low-income customers and economic development over the three-year period ending December 31, 2008 which will not have an effect on net income. The plan also authorized each company to establish unavoidable riders applicable to all distribution customers in order to be compensated in 2006 through 2008 for certain new costs incurred in 2004 and 2005 of fulfilling the companies' Provider of Last Resort (POLR) obligations. These costs include RTO administrative fees and congestion costs net of financial transmission revenues and carrying cost of environmental capital expenditures. As a result, in 2005, CSPCo and OPCo expect to record regulatory assets of approximately $8 million and $21 million, respectively, for the subject costs related to 2004 and $14 million and $52 million, respectively, for expected subject costs related to 2005. These regulatory assets totaling $22 million for CSPCo and $73 million for OPCo will be amortized as the costs are recovered through POLR riders in 2006 through 2008. The riders, together with the fixed annual increases in generation rates are estimated to provide additional cumulative revenues to CSPCo and OPCo of $190 million and $500 million, respectively, in the three-year period ended December 31, 2008. Other revenue increases may occur related to other provisions of the plan discussed above.

On February 25, 2005, various intervenors filed Applications for Rehearing with the PUCO regarding their approval of the rate stabilization plans. Management expects the PUCO to address the applications before the end of March 2005. Management cannot predict the ultimate impact these proceedings will have on the results of operations and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, we are deferring customer choice implementation costs and related carrying costs in excess of $40 million. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. Through December 31, 2004, we incurred $78 million of such costs, and accordingly, we deferred $38 million such costs for probable future recovery in distribution rates. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the rate stabilization plan, recovery of these amounts will be deferred until the next distribution rate filing to change rates after December 31, 2008. Management believes that the deferred customer choice implementation costs were prudently incurred and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING

Texas Restructuring Legislation enacted in 1999 provides the framework and timetable to allow retail electricity competition for all Texas customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007. TCC and TNC operate in ERCOT while SWEPCo and a small portion of TNC's business is in SPP.

The Texas Restructuring Legislation, among other things:

- provides for the recovery of net stranded generation costs and other generation true-up amounts through securitization and nonbypassable wires charges,
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility,
- provides for an earnings test for each of the years 1999 through 2001 and,
- provides for a stranded cost True-up Proceeding after January 10, 2004.

The Texas Restructuring Legislation also required vertically integrated utilities to legally separate their generation and retail-related assets from their transmission and distribution-related assets. Prior to 2002, TCC and TNC functionally separated their operations. AEP formed new subsidiaries to act as affiliated REPs for TCC and TNC effective January 1, 2002 (the start date of retail competition). In December 2002, AEP sold two of its affiliated price-to-beat REPs serving ERCOT customers to a nonaffiliated company.

TEXAS TRUE-UP PROCEEDINGS

The True-up Proceedings will determine the amount and recovery of:

- net stranded generation plant costs and net generation-related regulatory assets less any unrefunded excess earnings (net stranded generation costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the projected power costs used in the PUCT's excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up revenues),
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
- final approved deferred fuel balance, and
- net carrying costs on true-up amounts.

The PUCT adopted a rule in 2003 regarding the timing of the True-up Proceedings scheduling TCC's filing 60 days after the completion of the sale of TCC's generation assets. Due to regulatory and contractual delays in the sale of its generating assets, TCC has not yet filed its true-up request. TNC filed its true-up request in June 2004 and updated the filing in October 2004. Since TNC is not a stranded cost company under Texas Restructuring Legislation, the majority of the true-up items in the table below do not apply to TNC.

Net True-up Regulatory Asset (Liability) Recorded at December 31, 2004:

	TCC	TNC
	(in millions)	
Stranded Generation Plant Costs	$ 897	$ -
Net Generation-related Regulatory Asset	249	-
Unrefunded Excess Earnings	(10)	-
Net Stranded Generation Costs	1,136	-
Carrying Costs on Stranded Generation Plant Costs	225	-
Net Stranded Generation Costs Designated for Securitization	1,361	-
Wholesale Capacity Auction True-up	483	-
Carrying Costs on Wholesale Capacity Auction True-up	77	-
Retail Clawback	(61)	(14)
Deferred Over-recovered Fuel Balance	(212)	(4)
Net Other Recoverable True-up Amounts	287	(18)
Total Recorded Net True-up Regulatory Asset (Liability)	$ 1,648	$ (18)

Amounts listed above include fourth quarter 2004 adjustments made to reflect the applicable portion of the PUCT's decisions in prior nonaffiliated utilities' True-up Proceedings discussed below.

Net Stranded Generation Costs

The Texas Restructuring Legislation required utilities with stranded generation plant costs to use market-based methods to value certain generation assets for determining stranded generation plant costs. TCC is the only AEP subsidiary that has stranded generation plant costs under the Texas Restructuring Legislation. TCC elected to use the sale of assets method to determine the market value of its generation assets for determining stranded generation plant costs. For purposes of the True-up Proceeding, the amount of stranded generation plant costs under this market valuation methodology will be the amount by which the book value of TCC's generation assets exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCC's generation capacity in Texas. We received bids for all of TCC's generation plants. In January 2004, TCC agreed to sell its 7.81% ownership interest in the Oklaunion Power Station to a nonaffiliated third party for approximately $43 million. In March 2004, TCC agreed to sell its 25.2% ownership interest in STP for approximately $333 million and its other coal, gas and hydro plants for approximately $430 million to nonaffiliated entities. Each sale is subject to specified price adjustments. TCC sent right of first refusal notices to the co-owners of Oklaunion and STP. TCC filed for FERC approval of the sales of Oklaunion, STP and the coal, gas and hydro plants. TCC received a notice from co-owners of Oklaunion and STP exercising their rights of first refusal; therefore, SEC approval will be required. The original nonaffiliated third party purchaser of Oklaunion has petitioned for a court order declaring its contract valid and the co-owners' rights of first refusal void. The sale of STP will also require approval from the Nuclear Regulatory Commission. On July 1, 2004, TCC completed the sale of its other coal, gas and hydro plants for approximately $428 million, net of adjustments. The closings of the sales of STP and Oklaunion plants are expected to occur in the first half of 2005, subject to resolution of the rights of first refusal issues and obtaining the necessary regulatory approvals. In addition, there could be delays in resolving litigation with a third party affecting Oklaunion. In order to sell these assets, TCC defeased all of its remaining outstanding first mortgage bonds in May 2004. In December 2003, based on an expected loss from the sale of its generating assets, TCC recognized as a regulatory asset an estimated impairment from the sale of TCC's generation assets of approximately $938 million. The impairment was computed based on an estimate of TCC's generation assets sales price compared to book basis at December 31, 2003. On February 15, 2005, TCC filed with the PUCT requesting a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closings of the sales of all the generation assets. TCC asked the PUCT to rule on the request in April 2005.

On December 17, 2004, the PUCT issued an Order on Rehearing in the CenterPoint True-Up Proceeding (CenterPoint Order). All motions for rehearing of that order were denied on January 18, 2005, and the PUCT's decision is now final and appealable. Among other things, the CenterPoint Order provided certain adjustments to stranded generation plant costs to avoid what the PUCT deemed to be duplicative recovery of stranded costs and the capacity auction true-up amount, as further discussed below (See "Wholesale Capacity Auction True-up" below). The CenterPoint Order also confirmed that stranded costs are to be determined as of December 31, 2001, and, as also discussed below, the CenterPoint Order identified how carrying costs from that date are to be computed (see "Carrying Costs on Net True-Up Regulatory Assets" below).

In the fourth quarter of 2004, TCC made adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis (instead of December 31, 2003 book basis), including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCC's stranded generation plant costs regulatory asset was reduced by $238 million based on a PUCT adjustment in the CenterPoint Order discussed below under "Wholesale Capacity Auction True-up." These adjustments are reflected as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax in our Consolidated Statements of Operations. Management believes that with these adjustments to TCC's stranded generation plant costs regulatory asset, it has complied with the portions of the PUCT's to-date orders in other Texas companies' true-up proceedings that apply to TCC.

In addition to the two items discussed above (the $938 million impairment in 2003 and the $185 million adjustment in 2004), TCC had recorded $121 million of impairments in 2002 and 2003 on its gas-fired plants. Additionally, other miscellaneous items and the costs to complete the sales, which are still ongoing, of $23 million are included in the recoverable stranded generation plant costs of $897 million.

The Texas Restructuring Legislation permits TCC to recover as its net stranded generation costs $897 million of net stranded generation plant cost plus its remaining not yet securitized net generation-related transition regulatory asset of $249 million less a regulatory liability for the unrefunded excess earnings of $10 million, discussed below. With the above net extraordinary basis adjustments from applicable portions of the PUCT's prior nonaffiliated true-up orders, TCC's net stranded generation costs before carrying costs totaled $1.1 billion at December 31, 2004.

In the CenterPoint Order, the PUCT decided that net stranded generation costs should be reduced by the present value of deferred investment tax credits (ITC) and excess deferred federal income taxes applicable to generating assets. CenterPoint testified in its true-up proceeding that acceleration of the sharing of deferred ITC with customers may be a violation of the Internal Revenue Code's normalization provisions. Management agrees with CenterPoint that the PUCT's acceleration of deferred ITC and excess deferred federal income taxes may be a violation of the normalization provisions. As a result, management does not intend to include as a reduction of its net stranded generation costs the present value of TCC's generation-related deferred ITC of $70 million and the present value of excess deferred federal income taxes of $6 million in its future true-up filing. As a result, such amounts are not reflected as a reduction of TCC's net stranded generation costs in the above table. The Internal Revenue Service (IRS) has issued proposed regulations that would make an exception to the normalization provisions for a utility whose electric generation assets cease to be public utility property. If the IRS does not issue final regulations with protective provisions prior to the filing of TCC's true-up, management intends to seek a private letter ruling from the IRS to determine whether the PUCT's action would result in a normalization violation. A normalization violation could result in the repayment of TCC's accumulated deferred ITC on all property, not just generation property, which approximates $108 million as of December 31, 2004, and a loss of the ability to elect accelerated tax depreciation in the future. Management is unable to predict how the IRS will rule on a private letter ruling request and whether TCC will ultimately suffer any adverse effects on its future results of operations and cash flows.

Unrefunded Excess Earnings

The Texas Restructuring Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined by the PUCT for this three-year period were $3 million for SWEPCo, $42 million for TCC and $15 million for TNC. TCC, TNC and SWEPCo challenged the PUCT's treatment of fuel-related deferred income taxes in the computation of excess earnings and appealed the PUCT's final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. However, upon further appeal of the District Court ruling upholding the PUCT decision, the Third Court of Appeals reversed the PUCT order and the District Court's judgment. The District Court remanded to the PUCT an appeal of the same issue from the PUCT's 2001 order upon agreement of the parties after issuance of the Third Court of Appeals decision. On September 14, 2004, the parties to the PUCT remand reached an agreement, which changed the method for calculating excess earnings which, in turn, revised the calculation for 2000 and 2001 consistent with the ruling of the court. The PUCT issued a final order approving the agreement in October 2004. Since an expense and regulatory liability had been accrued in prior years in compliance with the PUCT orders, all three companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Court's decision and credited amortization expense during the third quarter of 2003. Under the Texas Restructuring Legislation, since TNC and SWEPCo do not have stranded generation plant costs, excess earnings have been applied to reduce T&D capital expenditures and are not a true-up item.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order had no additional effect on reported net income but reduces cash flows over the refund period. The remaining $10 million to be refunded is recorded as a regulatory liability at December 31, 2004 and will be included as a reduction to TCC's net stranded generation costs unless it has been fully refunded. Management believes that TCC has stranded generation plant costs and that it is, therefore, inconsistent with the Texas Restructuring Legislation for the PUCT to have ordered a refund prior to TCC's True-up Proceeding. TCC appealed the PUCT's premature refund of excess earnings to the Travis County District Court. That court affirmed the PUCT's decision and further ordered that the refunds be provided to ultimate customers. TCC has appealed the decision to the Third Court of Appeals.

In January 2005, intervenors filed testimony in TNC's True-up Proceeding recommending that TNC's excess earnings be increased by approximately $5 million to reflect carrying charges on its excess earnings for the period from January 1, 2002 to March 2005. A decision from the PUCT will likely be received in the second quarter of 2005.

Wholesale Capacity Auction True-up

The Texas Restructuring Legislation required that electric utilities and their affiliated power generation companies (PGCs) offer for sale at auction, in 2002, 2003 and thereafter, at least 15% of the PGCs' Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation. According to the legislation, the actual market power prices received in the state-mandated auctions are used to calculate wholesale capacity auction true-up revenues for recovery in the True-up Proceeding. According to PUCT rules, the wholesale capacity auction true-up is only applicable to the years 2002 and 2003. Based on its auction prices, TCC recorded a regulatory asset and related revenues of $262 million in 2002 and $218 million in 2003 which represented the quantifiable amount of the wholesale capacity auction true-up. The cumulative amount before carrying costs was adjusted to $483 million in the fourth quarter of 2004. TCC also recorded $77 million of carrying costs in the fourth quarter of 2004 related to the wholesale capacity auction true-up, increasing the total asset to $560 million.

In the CenterPoint Order, the PUCT made three significant adverse adjustments to CenterPoint's and its affiliated PGCs' request for recovery related to its capacity auction true-up regulatory asset. First, the PUCT determined that CenterPoint had not met what the PUCT interpreted as a requirement to sell 15% of its generation capacity at the state-mandated auctions. Accordingly, an adjustment was made to reflect prices obtained in other auctions of CenterPoint's affiliated PGCs' generation. Parties to the TCC proceeding may also contend that TCC has not met the requirement to auction 15% of its generation capacity. However, based on facts not applicable to the CenterPoint case, TCC will contend that it has met the requirement. Even if it were determined that TCC has not complied with the requirement, facts unique to TCC might mitigate the potential impact and make the method of calculating an impact uncertain. Since the facts in the CenterPoint decision differ from TCC's facts and circumstances, TCC has not recorded any provisions to reflect a similar adverse adjustment to its net true-up regulatory asset.

Second, the PUCT determined that the purpose of the capacity auction true-up is to provide a traditional regulated level of recovery during 2002-2003. The PUCT then determined that depreciation is a component of that recovery and, because depreciation represents a return of investment in generation assets, it disallowed 2002 and 2003 depreciation as a duplicative recovery of stranded costs. In the CenterPoint Order, the PUCT determined that there was a duplication of depreciation due to the fact that the stranded generation plant costs also include amounts depreciated in 2002 and 2003 because the stranded generation plant costs were determined as of December 31, 2001. TCC disagrees that the purpose of the capacity auction true-up is to provide a traditional regulated recovery during 2002 through 2003. Moreover, TCC will contend, among other things, that the PUCT's method of calculating the capacity auction true-up did not permit TCC to fully recover 2002 through 2003 depreciation expense. Nonetheless, based on the determination made by the PUCT in the CenterPoint case and the probability that it will interpret the law in the same manner in TCC's case, TCC recorded a $238 million reduction to its stranded generation plant costs in December 2004 which is reflected as a component of the Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax in our Consolidated Statements of Operations.

Third, the PUCT determined in the CenterPoint case that any nonfuel revenues produced by the capacity auction true-up regulatory asset which exceed nonfuel revenues for 2002-2003 from traditional regulation is a margin or return which is duplicative of the carrying cost. As noted above, TCC intends to challenge the conclusion that the capacity auction true-up was intended to provide a traditional regulated recovery. In addition, TCC will contend, that when applied to TCC, the calculation adopted for CenterPoint in which the PUCT determined that CenterPoint had duplicative return of carrying costs actually produces a $206 million negative margin. It will be TCC's position that it should have the right to recover the negative margin if the purpose of the capacity auction is to allow a traditional regulated recovery. As a result, TCC has recorded no adjustment to reflect this determination in the CenterPoint case.

Retail Clawback

The Texas Restructuring Legislation provides for the affiliated PTB REPs serving residential and small commercial customers to refund to its T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is referred to as the the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. In December 2003, the PUCT certified that the REPs in the TCC and TNC service territories had reached the 40% threshold for the small commercial class. As a result, TCC and TNC reversed $6 million and $3 million, respectively, of retail clawback regulatory liabilities previously accrued for the small commercial class. Based upon customer information filed by the nonaffiliated company, which operates as the PTB REP for TCC and TNC, TCC and TNC updated their estimated residential retail clawback regulatory liability. At December 31, 2004, TCC's recorded retail clawback regulatory liability was $61 million and TNC's was $14 million. TCC and TNC each recorded a receivable from the nonaffiliated company which operates as their PTB REP totaling $32 million and $7 million, respectively, for their share of the retail clawback liability.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the True-up Proceeding. In October 2004, the PUCT issued a final order which resulted in an over-recovery balance of $4 million. TNC had adjusted its deferred fuel balance in 2003 by $20 million and in 2004 by $10 million in compliance with the final PUCT order. Challenges to that order were filed in December 2004 in federal and state district courts.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery fuel balance for inclusion in the True-up Proceeding. TCC provided for disallowances increasing its regulatory fuel over-recovery liability by $81 million in 2003 and $62 million in 2004. On February 24, 2005, the PUCT in its open meeting increased the over-recovery by approximately $2 million, inclusive of interest, for imputed capacity. TCC has provided for a $212 million deferred over-recovery fuel balance at December 31, 2004, which does not include the $2 million disallowance ruled by the PUCT. However, management is unable to predict the amount, if any, of any additional disallowances of TCC's final fuel over-recovery balance which will be included in its True-up Proceeding until a final order is issued. Management believes it has materially provided for probable to date disallowances in TCC's final fuel proceeding pending receipt of an order.

See "TCC Fuel Reconciliation" and "TNC Fuel Reconciliations" in Note 4 for further discussion.

Carrying Costs on Net True-up Regulatory Assets

In December 2001, the PUCT issued a rule concerning stranded cost true-up proceedings stating, among other things, that carrying costs on stranded costs would begin to accrue on the date that the PUCT issued its final order in the True-up Proceeding. TCC and one other Texas electric utility company filed a direct appeal of the rule to the Texas Third Court of Appeals contending that carrying costs should commence on January 1, 2002, the day that retail customer choice began in ERCOT.

The Third Court of Appeals ruled against the utilities, who then appealed to the Texas Supreme Court. On June 18, 2004, the Texas Supreme Court reversed the decision of the Third Court of Appeals determining that a carrying cost should be accrued beginning January 1, 2002 and remanded the proceeding to the PUCT for further consideration. The Supreme Court determined that utilities with stranded costs are not permitted to over-recover stranded costs and ordered that the PUCT should address whether any portion of the 2002 and 2003 wholesale capacity auction true-up regulatory asset includes a recovery of stranded costs or carrying costs on stranded costs. A motion for rehearing with the Supreme Court was denied and the ruling became final.

In the CenterPoint Order, the PUCT addressed the Supreme Court's remand decision and specified the manner in which carrying costs should be calculated. In December 2004, TCC computed, based on its interpretation of the methodology contained in the CenterPoint Order, carrying costs of $470 million for the period January 1, 2002 through December 31, 2004 on its stranded generation plant costs net of excess earnings and its wholesale capacity auction true-up regulatory assets at the 11.79% overall pretax cost of capital rate in its UCOS rate proceeding. The embedded 8.12% debt component of the carrying cost of $302 million ($225 million on stranded generation plant costs and $77 million on wholesale capacity auction true-up) was recognized in income in December 2004. This amount is included in Carrying Costs on Texas Stranded Cost Recovery in our Consolidated Statements of Operations. Of the $302 million recorded in 2004, approximately $109 million, $105 million and $88 million related to the years 2004, 2003 and 2002, respectively. The remaining equity component of $168 million will be recognized in income as collected.

TCC will continue to accrue a carrying cost at the rate set forth above until it recovers its approved net true-up regulatory asset. The deferred over-recovered fuel balance accrues interest payable at a short-term rate set by the PUCT until one year after a final order is issued in the fuel proceeding or a final order is issued in TCC's True-up Proceeding, whichever comes first. At that time, a carrying cost will begin to accrue on the deferred fuel. For all remaining true-up items, including the retail clawback, a carrying cost will begin to accrue when a final order is issued in TCC's True-up Proceeding. If the PUCT further adjusts TCC's net true-up regulatory asset in TCC's True-up Proceeding, the carrying cost will also be adjusted.

Stranded Cost Recovery

When the True-up Proceeding is completed, TCC intends to file to recover PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through nonbypassable transition charges and competition transition charges in the regulated T&D rates. TCC will seek to securitize the approved net stranded generation costs plus related carrying costs. The annual costs of the resultant securitization bonds will be recovered through a nonbypassable transition charge collected by the T&D utility over the term of the securitization bonds. The other approved net true-up items will be recovered or refunded over time through a nonbypassable competition transition wires charge or credit inclusive of a carrying cost.

TCC's recorded net true-up regulatory asset for amounts subject to approval in the True-up Proceeding is approximately $1.6 billion at December 31, 2004. The securitizable portion of this net true-up regulatory asset, which consists of net stranded generation costs plus related carrying costs, was $1.4 billion at December 31, 2004. We expect that TCC's True-up Proceeding filing will seek to recover an amount in excess of the total of its recorded net true-up regulatory asset through December 31, 2004. The PUCT will review TCC's filing and determine the amount for the recoverable net true-up regulatory assets.

Due to differences between CenterPoint's and TCC's facts and circumstances, the lack of direct applicability of certain portions of the CenterPoint Order to TCC and the unknown nature of future developments in TCC's True-up Proceeding, we cannot, at this time, determine if TCC will incur disallowances in its True-up Proceeding in excess of the $185 million provided in December 2004. We believe that our recorded net true-up regulatory asset at December 31, 2004 is in compliance with the Texas Restructuring Legislation, and the applicable portions of the CenterPoint Order and other nonaffiliated true-up orders, and we intend to seek vigorously its recovery. If, however, we determine that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.6 billion at December 31, 2004 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount, which could have a material adverse effect on future results of operations, cash flows and possibly financial condition. To the extent decisions in the TCC True-up Proceeding differ from management's interpretation of the Texas Restructuring Legislation and its evaluation of the applicable portions of the CenterPoint and other true-up orders, additional material disallowances are possible.

TNC 2004 True-up Filing

In June 2004, TNC filed its True-up Proceeding which included the fuel reconciliation balance and the retail clawback calculation. The amount of the deferred over-recovered fuel balance at December 31, 2004 was approximately $4 million. TNC filed an update to its true-up filing to reflect the final order in its fuel reconciliation proceeding. The retail clawback regulatory liability included in the filing was adjusted in 2004 to $14 million, reflecting the number of customers served on January 1, 2004. In January 2005, intervenors filed testimony recommending that TNC's over-recovery be increased by up to approximately $2 million. In addition, they recommended that TNC's excess earnings be increased by approximately $5 million for carrying charges and its T&D rates be reduced by a maximum amount of approximately $3 million on an annual basis to reflect the return on excess earnings approved by the PUCT for the period 1999 through 2001. TNC does not agree with the intervenor's reconciliation and filed rebuttal testimony. Management believes it has materially provided for all probable to date disallowances in TNC's True-up Proceeding.

MICHIGAN RESTRUCTURING

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date, the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total base rates in Michigan remain unchanged and reflect cost of service. At December 31, 2004, none of I&M's customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory. As a result, management has concluded that as of December 31, 2004 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

VIRGINIA RESTRUCTURING

In April 2004, the Governor of Virginia signed legislation that extends the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004.

ARKANSAS RESTRUCTURING

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCo's Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999. The reapplication of SFAS 71 had an insignificant effect on results of operations and financial condition.

WEST VIRGINIA RESTRUCTURING

In 2000, the Public Service Commission of West Virginia (WVPSC) issued an order approving an electricity-restructuring plan, which the West Virginia Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the West Virginia legislature made tax law changes necessary to preserve the revenues of state and local governments.

In the 2001 and 2002 legislative sessions, the West Virginia Legislature failed to enact the required legislation that would allow the WVPSC to implement the restructuring plan. Due to this lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring during the summer of 2002.

In the 2003 legislative session, the West Virginia Legislature again failed to enact the required tax legislation. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in West Virginia. In March 2003, APCo's outside counsel advised us that restructuring in West Virginia was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's West Virginia generation. As a result, in March 2003, management concluded that deregulation of APCo's West Virginia generation business was no longer probable and operations in West Virginia met the requirements to reapply SFAS 71. Reapplying SFAS 71 in West Virginia had an insignificant effect on 2003 results of operations and financial condition.

7. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states have alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

On June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to "perfect" its complaint in the pending litigation. The NOV expands the number of alleged "modifications" undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA filed a motion to amend its complaints and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, eight Northeastern States filed a separate complaint containing the same allegations against the Conesville and Amos plants that the judge disallowed in the pending case. AEP filed an answer to the complaint in January 2005, denying the allegations and stating its defenses.

On August 7, 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, a nonaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not "routine" maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any nonroutine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A remedy trial was scheduled for July 2004, but has been postponed to facilitate further settlement discussions.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in our case also vary widely from plant to plant. Further, the Ohio Edison decision is limited to liability issues, and provides no insight as to the remedies that might ultimately be ordered by the Court.

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, a nonaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that the Federal EPA bears the burden of proof on the issue of whether a practice is "routine maintenance, repair, or replacement" and on whether or not a "significant net emissions increase" results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is "routine within the relevant source category" in determining if it is "routine." Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA has requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals. The District Court denied the Federal EPA's motion. On April 13, 2004, the parties filed a joint motion for entry of final judgment, based on stipulations of relevant facts that eliminated the need for a trial, but preserving plaintiffs' right to seek an appeal of the federal prevention of significant deterioration (PSD) claims. On April 14, 2004, the Court entered final judgment for Duke Energy on all of the PSD claims made in the amended complaints, and dismissed all remaining claims with prejudice. The United States subsequently filed a notice of appeal to the Fourth Circuit Court of Appeals. The case is fully briefed and oral argument was heard on February 3, 2005.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for alleged CAA violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the CAA are unconstitutional. The United States filed a petition for certiorari with the United States Supreme Court and in May 2004, that petition was denied.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which our subsidiaries are members, to reopen petitions for review of the 1980 and 1992 CAA rulemakings that are the basis for the Federal EPA claims in our case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in our case. Briefing continues in this case and oral argument was held in January 2005.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines "routine maintenance repair and replacement" to include "functionally equivalent equipment replacement." Under the new rule, replacement of a component within an integrated industrial operation (defined as a "process unit") with a new component that is identical or functionally equivalent will be deemed to be a "routine replacement" if the replacement does not change any of the fundamental design parameters of the process unit, does not result in emissions in excess of any authorized limit, and does not cost more than twenty percent of the replacement cost of the process unit. The new rule is intended to have prospective effect, and was to become effective in certain states

60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003, twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

In December 2000, Cinergy Corp., a nonaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the CAA. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly-owned facilities and its future results of operations and cash flows.

On July 21, 2004, the Sierra Club issued a notice of intent to file a citizen suit claim against DPL, Inc., Cinergy Corporation, CSPCo, and The Dayton Power & Light Company for alleged violations of the New Source Review programs at the Stuart Station. CSPCo owns a 26% share of the Stuart Station. On September 21, 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio state implementation plan occurred at the Stuart Station, and seeking injunctive relief and civil penalties. The owners have filed a motion to dismiss portions of the complaint. We believe the allegations in the complaint are without merit, and intend to defend vigorously this action. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

We are unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions.

On July 19, 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On August 30, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the reporting of volatile organic compound emissions at the Pirkey Plant, but after investigation determined further enforcement action was not warranted and withdrew the notice on January 5, 2005.

SWEPCo has previously reported to the TCEQ deviations related to the receipt of off-specification fuel at Knox Lee, the volatile organic compound emissions at Pirkey, and the referenced recordkeeping and reporting requirements and heat input value at Welsh. We have submitted additional responses to the Notice of Enforcement and the notice from the special interest groups. Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of three special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. Management believes the actions are without merit and intends to defend vigorously against the claims.

NUCLEAR

Nuclear Plants

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement, I&M and TCC are 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. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $10.8 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $300 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 $101 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $20 million. TCC could be assessed $50 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited.

Under an industry-wide program insuring workers at nuclear facilities, I&M and TCC are also obligated for assessments of up to $6 million and $2 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. I&M and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $43 million for I&M and $2 million for TCC which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed in 2005 with increases in required third party financial protection for nuclear incidents.

SNF Disposal

Federal law provides for government responsibility 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 Cook Plant and STP is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $229 million for fuel consumed prior to April 7, 1983 at Cook Plant have been recorded as long-term debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2004, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. In November 2003, I&M filed to extend the operating licenses of the two Cook Plant units for up to an additional 20 years. The review of the license extension application is expected to take at least two years. After expiration of the licenses, Cook Plant is expected to be decommissioned using the prompt decontamination and dismantlement (DECON) method. The estimated cost of decommissioning and low-level radioactive waste accumulation disposal costs for Cook Plant ranges from $889 million to $1.1 billion in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $27 million in 2004, 2003 and 2002.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the DECON method. In May 2004, an updated decommissioning study was completed for STP. The study estimates TCC’s share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year. As discussed in Note 10, TCC is in the process of selling its ownership interest in STP to two nonaffiliates, and upon completion of the sale, it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

Decommissioning costs recovered from customers are deposited in external trusts. I&M deposited in its decommissioning trust an additional $4 million in 2004 and $12 million in both 2003 and 2002 related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in Other Operation expense for the Cook Plant. For STP, nuclear decommissioning costs are recorded in Other Operation expense, interest income of the trusts are recorded in Nonoperating Income and interest expense of the trust funds are included in Interest Charges.

TCC’s nuclear decommissioning trust asset and liability are included in held for sale amounts on the Consolidated Balance Sheets.

OPERATIONAL

Construction and Commitments

The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2005 for consolidated operations are estimated to be $2.7 billion including amounts for proposed environmental rules. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

Our subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The longest contract extends to the year 2014. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain conditions.

The AEP System has a unit contingent contract to supply approximately 250 MW of capacity to a nonaffiliated entity through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow) under a 5-year term with three 5-year renewal terms for a total term of up to 20 years. The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004. The initial term of our lease with Juniper (Juniper Lease) commenced on March 18, 2004 and terminates on June 17, 2009. We may extend the term of the Juniper Lease to a total lease term of 30 years. Our lease of the Facility is reported as an owned asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on our Consolidated Balance Sheets and the obligations under the lease agreement are excluded from the table of future minimum lease payment in Note 16.

Juniper is a nonaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility with debt financing of up to \$494 million and equity of up to \$31 million from investors with no relationship to AEP or any of AEP's subsidiaries.

The Facility is collateral for Juniper's debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Juniper's funded obligations as a liability of \$520 million. Upon expiration of the lease, our actual cash obligation could range from \$0 to \$415 million based on the fair value of the assets at that time. However, if we default under the Juniper Lease, our maximum cash payment could be as much as \$525 million.

We have the right to purchase the Facility for the acquisition cost during the last month of the Juniper Lease's initial term or on any monthly rent payment date during any extended term of the lease. In addition, we may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if we have arranged a sale of the Facility to a nonaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow as described below. If the lease is renewed for up to a 30-year lease term, then at the end of that 30-year term we may further renew the lease at fair market value subject to Juniper's approval, purchase the Facility at its acquisition cost, or sell the Facility, on behalf of Juniper, to an independent third party. If the Facility is sold and the proceeds from the sale are insufficient to pay all of Juniper's acquisition costs, we may be required to make a payment (not to exceed \$415 million) to Juniper for the excess of Juniper's acquisition cost over the proceeds from the sale. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report Juniper's funded obligations related to the

Facility on our Consolidated Balance Sheets, the fair value of the liability for our guarantee (the $415 million payment discussed above) is not separately reported.

At December 31, 2004, Juniper's acquisition costs for the Facility totaled $520 million, and the total acquisition cost for the completed Facility is currently expected to be approximately $525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR (plus a component for a fixed-rate return on Juniper's equity investment and an administrative charge). Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately $23 million represent future minimum lease payments to Juniper during the initial term. The majority of the payment is calculated using the indexed LIBOR rate (2.55% at December 31, 2004). Annual sublease payments received from Dow are approximately $27 million (substantially based on an adjusted three-month LIBOR rate discussed above).

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW).

OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000, (PPA), at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purpose of the PPA began April 2, 2004.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEP's breaches. If the PPA is deemed terminated or found to be unenforceable by the court, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM (Tractebel SA) has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable. On January 21, 2005, the District Court granted AEP partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA. The litigation is in the discovery phase, with trial scheduled to begin in March 2005.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the "Commercial Operations Date." Despite OPCo's prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCo's tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for these electric power products under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo, (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the District Court that the PPA has been terminated and (iii) would be pursuing against TEM, and Tractebel SA under the guaranty, damages and the full termination payment value of the PPA.

See "Power Generation Facility" section of Note 10 for further discussion.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be “physically interconnected” and confined to a “single area or region.” In January 2005, a hearing was held before an ALJ. We expect an initial decision from the ALJ later this year. The SEC will review the initial decision.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Enron Bankruptcy

In 2002, certain of our subsidiaries filed claims against Enron and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron’s bankruptcy, certain of our subsidiaries had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron’s bankruptcy.

Enron Bankruptcy – Bammel storage facility and HPL indemnification matters – In connection with the 2001 acquisition of HPL, we entered into a prepaid arrangement under which we acquired exclusive rights to use and operate the underground Bammel gas storage facility and appurtenant pipeline pursuant to an agreement with BAM Lease Company. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years.

In January 2004, we filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron did not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In April 2004, AEP and Enron entered into a settlement agreement under which we acquired title to the Bammel gas storage facility and related pipeline and compressor assets, plus 10.5 billion cubic feet (BCF) of natural gas currently used as cushion gas for $115 million, which increased our investment in HPL. AEP and Enron agreed to release each other from all claims associated with the Bammel facility, including our indemnity claims. The settlement received Bankruptcy Court approval in September 2004 and closed in November 2004. The parties’ respective trading claims and Bank of America’s (BOA) purported lien on approximately 55 BCF of natural gas in the Bammel storage reservoir (as described below) are not covered by the settlement agreement.

Enron Bankruptcy – Right to use of cushion gas agreements – In connection with the 2001 acquisition of HPL, we also entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 BCF of cushion gas (including the 10.5 BCF described in the preceding paragraph) 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 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in state court in Texas seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOA’s claims.

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA's Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA has objected to the Magistrate Judge's decision and the matter is now before the District Judge.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements.

On January 26, 2005, we sold a 98% limited partner interest in HPL. We have indemnified the buyer of our 98% interest in HPL against any damages resulting from the BOA litigation. The determination of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the BOA dispute (see Note 19).

Enron Bankruptcy – Commodity trading settlement disputes – In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. We asserted our right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. The parties are currently in nonbinding, court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claim in the action being brought by Enron. The parties are currently in nonbinding, court-sponsored mediation.

Enron Bankruptcy – Summary – The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and there is a dispute regarding the cushion gas agreement. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows or financial condition.

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, lawsuits alleging securities law violations and seeking class action certification were filed in federal District Court, Columbus, Ohio against AEP, certain AEP executives, and in some of the lawsuits, members of the AEP Board of Directors and certain investment banking firms. The lawsuits claim that we failed to disclose that alleged "round trip" trades resulted in an overstatement of revenues, that we failed to disclose that our traders falsely reported energy prices to trade publications that published gas price indices and that we failed to disclose that we did not have in place sufficient management controls to prevent "round trip" trades or false reporting of energy prices. The plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. In September 2004, the U.S. District Court Judge dismissed the cases and expressly denied the plaintiffs' request for an opportunity to file amended complaints with new and revised allegations. The plaintiffs did not appeal this decision.

In the fourth quarter of 2002, two shareholder derivative actions were filed in state court in Columbus, Ohio against AEP and its Board of Directors alleging a breach of fiduciary duty for failure to establish and maintain adequate internal controls over our gas trading operations. In November 2004, these cases were dismissed. Also, in the fourth quarter of 2002 and the first quarter of 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions are pending in federal District Court, Columbus, Ohio. In these actions, the plaintiffs seek recovery of an unstated amount of compensatory damages, attorney fees and costs. We have filed a Motion to Dismiss these actions, which the Court denied. We have filed a Motion for Leave to file an interlocutory appeal seeking review of part of the Court's decision. The cases are in the discovery stage. We intend to continue to defend vigorously against these claims.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County, California Superior Court against forty energy companies, including AEP, and two publishing companies 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 has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. Since then, a number of cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Management is unable to predict the outcome of these lawsuits but intends to defend vigorously against the claims made in each case where an AEP company is a defendant.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES, seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. On December 5, 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. We and the other defendants filed a motion to dismiss the complaint, which the Court denied in September 2004. We intend to defend vigorously against these claims.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against certain nonaffiliated energy companies, ERCOT, four AEP subsidiaries and us. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against the AEP companies. TCE has appealed the trial court's decision to the United States Court of Appeals for the Fifth Circuit.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals with us and claimed that we owed approximately $34 million. In April 2003, we filed a lawsuit in federal District Court in Columbus, Ohio against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately $68 million. We are claiming that BOM owes us at least $45 million related to previously recorded receivables on which we hold approximately $20 million of credit collateral. We have reserved $4 million against these receivables to reflect the risks of loss, based on the low end of a range of valuations calculated for purposes of the litigation and related mediation. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Coal Transportation Dispute

Certain of our subsidiaries, as joint owners of a generating station have disputed transportation costs billed for coal received between July 2000 and the present time. Our subsidiaries have remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, our subsidiaries recorded a provision for possible loss in December 2004. Of the total provision, a share for deregulated subsidiaries affected income in 2004, a share was recorded as a receivable due to partial ownership of the plant by third parties and the remainder was deferred under the operation of a deferred fuel mechanism. Management continues to work toward mitigating the disputed amounts to the extent possible.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by certain wholesale customers located in Nevada. The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were “high-priced.” The complaint alleged that we sold power at unjust and unreasonable prices. In December 2002, a FERC ALJ ruled in our favor and dismissed the complaint filed by the two Nevada utilities. In 2001, the utilities had filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities had failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ’s decision. The utilities’ request for a rehearing was denied. The utilities’ appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

Energy Market Investigation

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and continued to respond to supplemental data requests from some of these agencies in 2003 and 2004.

In September 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleged that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC sought civil penalties, restitution and disgorgement of benefits. We responded to the complaint in September 2004. In January 2005, we reached settlement agreements totaling $81 million with the CFTC, the U.S. Department of Justice and the FERC regarding investigations of past gas price reporting and gas storage activities, these being all agencies known still to be investigating these matters as to AEP. Our settlements do not admit nor should they be construed as an admission of violation of any applicable regulation or law. We made settlement payments to the agencies in the first quarter of 2005 in accordance with the respective contractual terms. The agencies have ended their investigations and the CFTC litigation filed in September 2003 has also ended. During 2003 and 2004, we provided for the settlements payment in the amounts of $45 million and $36 million (nondeductible for federal income tax purposes), respectively. We do not expect any impact on 2005 results of operations as a result of these investigations and settlements.

8. GUARANTEES

There are certain immaterial liabilities recorded for guarantees entered subsequent to December 31, 2002 in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." There is no collateral held in relation to any guarantees in 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 have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. We issued all of these LOCs in our ordinary course of business. At December 31, 2004, the maximum future payments for all the LOCs are approximately $242 million with maturities ranging from February 2005 to January 2011. As the parent of various subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

CSW Energy and CSW International

CSW Energy and CSW International, our subsidiaries, have guaranteed 50% of the required debt service reserve of Sweeny Cogeneration L.P. (Sweeny), an IPP of which CSW Energy is a 50% owner. The guarantee was provided in lieu of Sweeny funding the debt reserve as a part of a financing. In the event that Sweeny does not make the required debt payments, CSW Energy and CSW International have a maximum future payment exposure of approximately $4 million, which expires June 2020.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $53 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 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 a third party miner. At December 31, 2004, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

Effective July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46. SWEPCo does not have an ownership interest in Sabine.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We entered into several types of contracts, which would 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. We cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2004 and 2003, we entered into several sale agreements discussed in Note 10. These sale agreements include indemnifications with a maximum exposure of approximately $970 million. There are no material liabilities recorded for any indemnifications entered during 2004 or 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2004, the maximum potential loss for these lease agreements was approximately $42 million ($27 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

See Note 16 for disclosure of other lease residual value guarantees.

9. SUSTAINED EARNINGS IMPROVEMENT INITIATIVE

In response to difficult conditions in our business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

Termination benefits expense relating to 1,120 terminated employees totaling $75 million pretax was recorded in the fourth quarter of 2002. Of this amount, we paid $10 million to these terminated employees in the fourth quarter of 2002. No additional termination benefits expense related to the SEI initiative was recorded in 2004 or 2003. The remaining SEI related payments were made in 2003. The termination benefits expense is classified as Maintenance and Other Operation expense on our Consolidated Statements of Operations. We determined that the termination of the employees under our SEI initiative did not constitute a plan curtailment of any of our retirement benefit plans.

10. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

ACQUISITIONS

2002

Acquisition of Nordic Trading (Investments – UK Operations segment)

In January 2002, we acquired the trading operations, including key staff, of Enron's Norway and Sweden-based energy trading businesses (Nordic Trading). Results of operations are included in our Consolidated Statements of Operations from the date of acquisition. In the fourth quarter of 2002, a decision was made to exit this noncore European trading business. The sale of Nordic Trading in the second quarter of 2003 is discussed in the "Dispositions" section of this note.

Acquisition of USTI (Investments – Other segment)

In January 2002, we acquired 100% of the stock of United Sciences Testing, Inc. (USTI) for $13 million. USTI provides equipment and services related to automated emission monitoring of combustion gases to both our affiliates and external customers. Results of operations are included in our Consolidated Statements of Operations from the date of acquisition.

DISPOSITIONS

2004

Pushan Power Plant (Investments – Other segment)

In the fourth quarter of 2002, we began active negotiations to sell our interest in the Pushan Power Plant (Pushan) in Nanyang, China to our minority interest partner. A purchase and sale agreement was signed in the fourth quarter of 2003. The sale was completed in March 2004 for $61 million. An estimated pretax loss on disposal of $20 million ($13 million net of tax) was recorded in December 2002, based on an indicative price expression at that time, and was classified in Discontinued Operations. The effect of the sale on our 2004 results of operations was not significant.

Results of operations of Pushan have been classified as Discontinued Operations in our Consolidated Statements of Operations. The assets and liabilities of Pushan have been included in Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held For Sale, respectively, on our Consolidated Balance Sheets at December 31, 2003. See "Discontinued Operations" and "Assets Held for Sale" sections of this note for additional information.

LIG Pipeline Company and its Subsidiaries (Investments – Gas Operations segment)

As a result of our 2003 decision to exit our noncore businesses, we actively marketed LIG Pipeline Company which had approximately 2,000 miles of natural gas gathering and transmission pipelines in Louisiana and five gas processing facilities that straddle the system. After receiving and analyzing initial bids during the fourth quarter of 2003, we recorded a pretax impairment loss of $134 million ($99 million net of tax); of this pretax loss, $129 million relates to the impairment of goodwill and $5 million relates to other charges. In January 2004, a decision was made to sell LIG's pipeline and processing assets separate from LIG's gas storage assets. (See "Jefferson Island Storage & Hub, LLC" section of this note for further information.) In February 2004, we signed a definitive agreement to sell LIG Pipeline Company, which owned all of the pipeline and processing assets of LIG. The sale of LIG Pipeline Company and its assets for $76 million was completed in April 2004 and the impact on results of operations in 2004 was not significant. The assets and liabilities of LIG are classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on our Consolidated Balance Sheets at December 31, 2003. The results of operations (including the above-mentioned impairments and other related charges) are classified in Discontinued Operations in our Consolidated Statements of Operations. See "Discontinued Operations" and "Assets Held for Sale" sections of this note for additional information.

Jefferson Island Storage & Hub, LLC (Investments – Gas Operations segment)

In August 2004, a definitive agreement was signed to sell the gas storage assets of Jefferson Island Storage & Hub, LLC (JISH). The sale of JISH and its assets for $90 million was completed in October 2004. The sale resulted in a pretax loss of $12 million ($2 million net of tax). The assets and liabilities of JISH are classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on our Consolidated Balance Sheets at December 31, 2003. The results of operations and loss on sale of JISH are classified as Discontinued Operations in our Consolidated Statements of Operations. See "Discontinued Operations" and "Assets Held for Sale" sections of this note for additional information.

AEP Coal, Inc. (Investments – Other segment)

In October 2001, we acquired out of bankruptcy certain assets and assumed certain liabilities of nineteen coal mine companies formerly known as "Quaker Coal" and renamed "AEP Coal, Inc." During 2002, the coal operations suffered from a decline in prices and adverse mining factors resulting in significantly reduced mine productivity and revenue. Based on an extensive review of economically accessible reserves and other factors, future mine productivity and production is expected to continue below historical levels. In December 2002, a probability-weighted discounted cash flow analysis of fair value of the mines was performed which indicated a 2002 pretax impairment loss of $60 million including a goodwill impairment of $4 million. This impairment loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

In 2003, as a result of management's decision to exit our noncore businesses, we retained an advisor to facilitate the sale of AEP Coal, Inc. In the fourth quarter of 2003, after considering the current bids and all other options, we recorded a pretax charge of $67 million ($44 million net of tax) comprised of a $30 million asset impairment, a $25 million charge related to accelerated remediation cost accruals and a $12 million charge (accrued at December 31, 2003) related to a royalty agreement. These impairment losses were included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The assets and liabilities of AEP Coal, Inc. that are held for sale have been included in Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, in our Consolidated Balance Sheets at December 31, 2003.

In March 2004, an agreement was reached to sell assets, exclusive of certain reserves and related liabilities, of the mining operations of AEP Coal, Inc. We received approximately $9 million cash and the buyer assumed an additional $11 million in future reclamation liabilities. We retained an estimated $37 million in future reclamation liabilities. The sale closed in April 2004 and the effect of the sale on our 2004 results of operations was not significant. See "Assets Held for Sale" section of this note for additional information.

Independent Power Producers (Investments – Other segment)

During the third quarter of 2003, we initiated an effort to sell four domestic Independent Power Producer (IPP) investments accounted for under the equity method (two located in Colorado and two located in Florida). Our two Colorado investments included a 47.75% interest in Brush II, a 68-megawatt, gas-fired, combined cycle, cogeneration plant in Brush, Colorado and a 50% interest in Thermo, a 272-megawatt, gas-fired, combined cycle, cogeneration plant located in Ft. Lupton, Colorado. Our two Florida investments included a 46.25% interest in Mulberry, a 120-megawatt, gas-fired, combined cycle, cogeneration plant located in Bartow, Florida and a 50% interest in Orange, a 103-megawatt, gas-fired, combined cycle, cogeneration plant located in Bartow, Florida. In accordance with GAAP, we were required to measure the impairment of each of these four investments individually. Based on indicative bids, it was determined that an other than temporary impairment existed on the two equity method investments located in Colorado. A pretax impairment of $70 million ($46 million net of tax) was recorded in September 2003 as the result of the measurement of fair value that was triggered by our decision to sell these assets. This loss of investment value was included in Investment Value Losses on our Consolidated Statements of Operations for the period ending December 31, 2003.

In March 2004, we entered into an agreement to sell the four domestic IPP investments for a total sales price of $156 million, subject to closing adjustments. An additional pretax impairment of $2 million was recorded in June 2004 (recorded to Investment Value Losses) to decrease the carrying value of the Colorado plant investments to their estimated sales price, less selling expenses. We closed on the sale of the two Florida investments and the Brush II plant in Colorado in July 2004. The sale resulted in a pretax gain of $105 million ($64 million net of tax) generated primarily from the sale of the two Florida IPPs which were not originally impaired. The gain was recorded to Gain on Disposition of Equity Investments, Net in our 2004 Consolidated Statements of Operations. The sale of the Ft. Lupton, Colorado plant closed in October 2004 and did not have a significant effect on our 2004 results of operations. Prior to the completion of the sale of each of the four IPPs, the assets for each of the four IPPs have been included in Investments in Power and Distribution Projects.

U.K. Generation (Investments – UK Operations segment)

In December 2001, we acquired two coal-fired generation plants (U.K. Generation) in the U.K. for a cash payment of $942 million and assumption of certain liabilities. Subsequently and continuing through 2002, wholesale U.K. electric power prices declined sharply as a result of domestic over-capacity and static demand. External industry forecasts and our own projections made during the fourth quarter of 2002 indicated that this situation may extend many years into the future. As a result, the U.K. Generation fixed asset carrying value at year-end 2002 was substantially impaired. A December 2002 probability-weighted discounted cash flow analysis of the fair value of our U.K. Generation indicated a 2002 pretax impairment loss of $549 million ($414 million net of tax). This impairment loss is included in Discontinued Operations on our Consolidated Statements of Operations for the year ended December 31, 2002.

In the fourth quarter of 2003, the U.K. generation plants were determined to be noncore assets and management engaged an investment advisor to assist in determining the best methodology to exit the U.K. business. Based on bids received and other market information, we recorded a pretax charge of $577 million ($375 net of tax), including asset impairments of $421 million during the fourth quarter of 2003 to write down the value of the assets to their estimated realizable value. Additional pretax charges of $157 million were also recorded in December 2003, including $122 million related to the net loss on certain cash flow hedges previously recorded in Accumulated Other Comprehensive Income (Loss) that were reclassified into earnings as a result of management's determination that the hedged event was no longer probable of occurring and $35 million related to a first quarter of 2004 sale of certain power contracts. All write downs related to the U.K. that were booked in the fourth quarter of 2003 were included in Discontinued Operations of our Consolidated Statements of Operations for the year ended December 31, 2003. The assets and liabilities of U.K. Generation have been classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on our December 31, 2003 Consolidated Balance Sheets.

In July 2004, we completed the sale of substantially all operations and assets within the U.K. The sale included our two coal-fired generation plants (Fiddler's Ferry and Ferrybridge), related coal assets, and a number of related commodities contracts for approximately $456 million. The sale resulted in a pretax gain of $266 million ($128 million net of tax). As a result of the sale, the buyer assumed an additional $46 million in future reclamation liabilities and $10 million in pension liabilities. The remaining assets and liabilities include certain physical power and capacity positions and financial coal and freight swaps. Substantially all of these positions mature or have been settled with the applicable counterparties during the first quarter of 2005. The results of operations and gain on sale are included in Discontinued Operations on our Consolidated Statements of Operations for the year ended December 31, 2004. See "Discontinued Operations" and "Assets Held for Sale" sections of this note for additional information.

Texas Plants – TCC and TNC Generation Assets (Utility Operations segment)

In September 2002, AEP indicated to ERCOT its intent to deactivate 16 gas-fired power plants (8 TCC plants and 8 TNC plants). ERCOT subsequently conducted reliability studies, which determined that seven plants (4 TCC plants and 3 TNC plants) would be required to ensure reliability of the electricity grid. As a result of those studies, ERCOT and AEP mutually agreed to enter into reliability-must-run (RMR) agreements, which expired in December 2002, and were subsequently renewed through December 2003. However, certain contractual provisions provided ERCOT with a 90-day termination clause if the contracted facility was no longer needed to ensure reliability of the electricity grid. With ERCOT's approval, AEP proceeded with its planned deactivation of the remaining nine plants. In August 2003, pursuant to contractual terms, ERCOT provided notification to AEP of its intent to cancel a RMR agreement at one of the TNC plants. Upon termination of the agreement, AEP proceeded with its planned deactivation of the plant. In December 2003, AEP and ERCOT mutually agreed to renew RMR contracts at the six plants (4 TCC plants and 2 TNC plants) through December 2004, subject to ERCOT's 90-day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate the TNC plants, a pretax write-down of utility assets of approximately $34 million was recorded in Asset Impairments and Other Related Charges expense during the third quarter of 2002 on our Consolidated Statements of Operations. The decision to deactivate the TCC plants resulted in a pretax write-down of utility assets of approximately $96 million, which was deferred and recorded in Regulatory Assets during the third quarter of 2002 in our Consolidated Balance Sheets.

During the fourth quarter of 2002, evaluations continued as to whether assets remaining at the deactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional pretax asset impairment charge to Asset Impairments and Other Related Charges expense of $4 million in the fourth quarter of 2002. In addition, TNC recorded related fuel inventory and materials and supplies write-downs of $3 million ($1 million in Fuel for Electric Generation and $2 million in Maintenance and Other Operation). Similarly, TCC recorded an additional pretax asset impairment write-down of $7 million, which was deferred and recorded in Regulatory Assets in the fourth quarter of 2002. TCC also recorded related inventory write-downs and adjustments of $18 million which were deferred and recorded in Regulatory Assets.

The total Texas plant pretax asset impairment of $38 million in 2002 (all related to TNC) is included in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

During the fourth quarter of 2003, after receiving indicative bids from interested buyers, we recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to Assets of Discontinued Operations and Held for Sale on our Consolidated Balance Sheets. In accordance with Texas legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the True-up Proceeding. As a result of the True-up Proceeding, if we are unable to recover all or a portion of our requested costs (see “Net Stranded Generation Costs” section of Note 6), any unrecovered costs could have a material adverse effect on our results of operations, cash flows and possibly financial condition.

In March 2004, we signed an agreement to sell eight natural gas plants, one coal-fired plant and one hydro plant to a nonrelated joint venture. The sale was completed in July 2004 for approximately $428 million, net of adjustments. The sale did not have a significant effect on our results of operations during the period ended December 31, 2004.

In December 2004, we recorded a pretax deduction of $185 million ($121 million net of tax) related to the TCC true-up regulatory asset for stranded generation plant costs (see “Net Stranded Generation Costs” section of Note 6). This deduction is shown as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax on our 2004 Consolidated Statements of Operations.

The remaining generation assets and liabilities of TCC are classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on our Consolidated Balance Sheets. See “Assets Held for Sale” section of this note for additional information.

South Coast Power Limited (Investments – Other Segment)

South Coast Power Limited (SCPL) is a 50% owned venture that was formed in 1996 to build, own and operate Shoreham Power Station, a 400-megawatt, combined-cycle, gas turbine power station located in Shoreham, England. In 2002, SCPL was subject to adverse wholesale electric power rates. A December 2002 projected cash flow estimate of the fair value of the investment indicated a 2002 pretax other than temporary impairment of the equity interest in the amount of $63 million. This loss of investment value was included in Investment Value Losses in the 2002 Consolidated Statements of Operations.

In the fourth quarter of 2003, management determined that our U.K. operations were no longer part of our core business and as a result, a decision was made to exit the U.K. market. In September 2004, we completed the sale of our 50% ownership in SCPL for $47 million, resulting in a pretax gain of $48 million ($31 million net of tax) in the third quarter of 2004. This gain was recorded to Gain on Disposition of Equity Investments, Net in our Consolidated Statements of Operations for the period ended December 31, 2004. The gain reflects improved conditions in the U.K. power market.

Excess Real Estate (Investments – Other segment)

In the fourth quarter of 2002, we began to market an under-utilized office building in Dallas, Texas obtained through our merger with CSW in June 2000. One prospective buyer executed an option to purchase the building. The sale of the facility was projected by second quarter of 2003 and an estimated 2002 pretax loss on disposal of $16 million was recorded, based on the option sale price. The estimated loss was included in Asset Impairments and Other Related Charges in our 2002 Consolidated Statements of Operations. We recorded an additional pretax impairment of $6 million in Maintenance and Other Operation in our 2003 Consolidated Statements of Operations based on market data. The original prospective buyer did not complete their purchase of the building by the end of 2003, and thus, the asset no longer qualified for held for sale status. The building was then reclassified to held and used status as of December 31, 2003.

In June 2004, we entered into negotiations to sell the Dallas office building. This resulted in the asset again being classified as held for sale in the second quarter of 2004. An additional pretax impairment of $3 million was recorded in Maintenance and Other Operation expense during the second quarter of 2004 to write down the value of the office building to the current estimated sales price, less estimated selling expenses. In October 2004, we completed the sale of the Dallas office building for $8 million. The sale did not have a significant effect on our results of operations. The property asset of $12 million at December 31, 2003 has been classified on our Consolidated Balance Sheets as Assets of Discontinued Operations and Held for Sale. See "Assets Held for Sale" section of this note for additional information.

Numanco LLC (Investments – Other segment)

In November 2004, we completed the sale of Numanco LLC for a sale price of $25 million. Numanco was a provider of staffing services to the utility industry. The sale did not have a significant effect on our 2004 results of operations.

2003

C3 Communications (Investments – Other segment)

In February 2003, C3 Communications sold the majority of its assets for a sales price of $7 million. We provided for a pretax asset impairment of $82 million ($53 million net of tax) in December 2002 and the effect of the sale on 2003 results of operations was not significant. The impairment is classified in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

Mutual Energy Companies (Utility Operations segment)

On December 23, 2002, we sold the general partner interests and the limited partner interests in Mutual Energy CPL LP and Mutual Energy WTU LP for a base purchase price paid in cash at closing and certain additional payments, including a net working capital payment. The buyer paid a base purchase price of $146 million which was based on a fair market value per customer established by an independent appraiser and an agreed customer count. We recorded a pretax gain of $129 million ($84 million net of tax) in Other Income during 2002. We provided the buyer with a power supply contract for the two REPs and back-office services related to these customers for a two-year period. In addition, we retained the right to share in earnings from the two REPs above a threshold amount through 2006 in the event the Texas retail market develops increased earnings opportunities. No revenue was recorded in 2004 and 2003 related to these sharing agreements, pending resolution of various contracted matters. Under the Texas Restructuring Legislation, REPs are subject to a clawback liability if customer change does not attain thresholds required by the legislation. We are responsible for a portion of such liability, if any, for the period we operated the REPs in the Texas competitive retail market (January 1, 2002 through December 23, 2002). In addition, we retained responsibility for regulatory obligations arising out of operations before closing. Our wholly-owned subsidiary, Mutual Energy Service Company LLC (MESC), received an up-front payment of approximately $30 million from the buyer associated with the back-office service agreement, and MESC deferred its right to receive payment of an additional amount of approximately $9 million to secure certain contingent obligations. These prepaid service revenues were deferred on the books of MESC as of December 31, 2002 and were amortized over the two-year term of the back-office service agreement.

In February 2003, we completed the sale of MESC for $30 million dollars and realized a pretax gain of approximately $39 million, which included the recognition of the remaining balance of the original prepayment of $30 million ($27 million), as no further service obligations existed for MESC. This gain was recorded in Other Income in our Consolidated Statements of Operations.

Water Heater Assets (Utility Operations segment)

We sold our water heater rental program for $38 million and recorded a pretax loss of $4 million in the first quarter of 2003 based upon final terms of the sale agreement. We had provided for a pretax charge of $7 million in the fourth quarter of 2002 based on an estimated sales price ($3 million asset impairment charge and $4 million lease prepayment penalty). The impairment loss is included in Investment Value Losses in our Consolidated Statements of Operations. We operated a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale.

AEP Gas Power Systems LLC (Investments – Other segment)

In 2001, we acquired a 75% interest in a startup company, seeking to develop low-cost peaking generator sets powered by surplus jet turbine engines. In January 2003, AEP Gas Power Systems LLC sold its assets. We recognized a pretax goodwill impairment loss of $12 million in the first quarter of 2002 based on cash flow studies that reflect technological and operational problems associated with the underlying technology (also see "Goodwill" section of Note 3). The impairment loss was recorded in Investment Value Losses on our Consolidated Statements of Operations. The effect of the asset sale on the 2003 results of operations was not significant.

Newgulf Facility (Investments – Other segment)

In 1995, we purchased an 85 MW gas-fired peaking electrical generation facility located near Newgulf, Texas (Newgulf). In October 2002, we began negotiations with a likely buyer of the facility. We estimated a pretax loss on sale of $12 million based on the indicative bid. This loss was recorded as Asset Impairments and Other Related Charges on our Consolidated Statements of Operations during the fourth quarter of 2002. During the second quarter of 2003, we completed the sale of Newgulf and the impact on earnings in 2003 was not significant.

Nordic Trading (Investments – UK Operations segment)

In October 2002, we announced that our ongoing energy trading operations would be centered around our generation assets. As a result, we took steps to exit our coal, gas and electricity trading activities in Europe with the exception of those activities predominantly related to our U.K. generation operations. The Nordic Trading business acquired earlier in 2002 was made available for sale to potential buyers later in 2002. The estimated pretax loss on disposal recorded in 2002 of $5 million consisted of impairment of goodwill of $4 million and impairment of assets of $1 million. The estimated loss of $5 million is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. Management's determination of a zero fair value was based on discussions with a potential buyer. The transfer of the Nordic Trading business, including the trading portfolio, to new owners was completed during the second quarter of 2003 and the impact on earnings during 2003 was not significant.

Eastex (Investments – Other segment)

In 1998, we began construction of a natural gas-fired cogeneration facility (Eastex) located near Longview, Texas and commercial operations commenced in December 2001. In June 2002, we requested that the FERC allow us to modify the FERC Merger Order and substitute Eastex as a required divestiture under the order due to the fact that the agreed upon market-power related divestiture of a plant in Oklahoma was no longer feasible. The FERC approved the request at the end of September 2002. Subsequently, in the fourth quarter of 2002, we solicited bids for the sale of Eastex and several interested buyers were identified by December 2002. The estimated pretax loss on the sale of $219 million ($142 million net of tax), which was based on the estimated fair value of the facility and indicative bids by interested buyers, was recorded in Discontinued Operations in our Consolidated Statements of Operations during the fourth quarter of 2002.

We completed the sale of Eastex during the third quarter of 2003 and the effect of the sale on 2003 results of operations was not significant. The results of operations of Eastex have been reclassified as Discontinued Operations in accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," for all years presented. See the "Discontinued Operations" section of this note for additional information.

Grupo Rede Investment (Investments – Other segment)

In December 2002, we recorded a pretax other than temporary impairment loss of $217 million ($141 million net of tax) of our 44% equity investment in Vale and our 20% equity interest in Caiua, both Brazilian electric operating companies (referred to as Grupo Rede). This impairment was due to the continuing decline in the Brazilian economy and currency which increased credit risks within Grupo Rede. This amount is included in Investment Value Losses on our 2002 Consolidated Statements of Operations.

In December 2003, we transferred our share and investment in Vale to Grupo Rede for $1 million. The effect of the transfer on our 2003 results of operations was not significant.

Excess Equipment (Investments – Other segment)

In November 2002, as a result of a cancelled development project, we obtained title to a surplus gas turbine generator. We were unsuccessful in finding potential buyers of the unit due to an over-supply of generation equipment available for sale during 2002. An estimated pretax loss on disposal of $24 million was recorded in December 2002, based on market prices of similar equipment. The loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

We completed the sale of the surplus gas turbine generator in November 2003. The proceeds from the sale were $9 million. A pretax loss of $2 million was recorded in the fourth quarter of 2003.

Ft. Davis Wind Farm (Investments – Other segment)

In the 1990's, we developed a 6 MW wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002, our engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility was completed in 2004. An estimated pretax loss on abandonment of $5 million was recorded in December 2002. The loss was recorded in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

2002

SEEBOARD (Investments – Other segment)

On June 18, 2002, through a wholly-owned subsidiary, we entered into an agreement, subject to European Union (EU) approval, to sell our consolidated subsidiary SEEBOARD, a U.K. electricity supply and distribution company. EU approval was received July 25, 2002 and the sale was completed on July 29, 2002. We received approximately $941 million in net cash from the sale, subject to a working capital true-up, and the buyer assumed SEEBOARD debt of approximately $1.1 billion, resulting in a net loss of $345 million at June 30, 2002. The results of operations of SEEBOARD have been classified as Discontinued Operations for all years presented. A pretax net loss of $22 million ($14 million net of tax) was classified as Discontinued Operations in the second quarter of 2002. The remaining $323 million of the net loss has been classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see "Goodwill and Other Intangible Assets" section of Note 2 and "Goodwill" section of Note 3) and has been reported as a Cumulative Effect of Accounting Change retroactive to January 1, 2002. A $59 million pretax reduction of the net loss ($38 million net of tax) was recognized in the second half of 2002 to reflect changes in exchange rates to closing, settlement of working capital true-up and selling expenses. The total net loss recognized on the disposal of SEEBOARD was $286 million. Proceeds from the sale of SEEBOARD were used to pay down bank facilities and short-term debt. See "Discontinued Operations" section of this note for additional information.

CitiPower (Investments – Other segment)

On July 19, 2002, through a wholly-owned subsidiary, we entered into an agreement to sell CitiPower, a retail electricity and gas supply and distribution subsidiary in Australia. We completed the sale on August 30, 2002 and received net cash of approximately $175 million and the buyer assumed CitiPower debt of approximately $674 million. We recorded a pretax charge of $192 million ($125 million net of tax) as of June 30, 2002. The charge included a pretax impairment loss of $151 million ($98 million net of tax) on the remaining carrying value of an intangible asset related to a distribution license for CitiPower. The remaining $41 million pretax net loss ($27 million net of tax) was classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see "Goodwill and Other Intangible Assets" section of Note 2 and "Goodwill" section of Note 3) and was recorded as a Cumulative Effect of Accounting Change retroactive to January 1, 2002.

The pretax loss on the sale of CitiPower increased $37 million ($24 million net of tax) to $229 million ($149 million net of tax; $122 million plus $27 million of cumulative effect) in the second half of 2002 based on actual closing amounts and exchange rates. See the "Discontinued Operations" section of this note for additional information.

DISCONTINUED OPERATIONS

Management periodically assesses the overall AEP 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 the operations of those businesses or operations as discontinued operations. The assets and liabilities of these discontinued operations are classified as Assets and Liabilities of Discontinued Operations and Held for Sale until the time that they are sold.

Certain of our operations were determined to be discontinued operations and have been classified as such in 2004, 2003 and 2002. Results of operations of these businesses have been classified as shown in the following table (in millions):

	SEE-BOARD	CitiPower	Eastex	Pushan Power Plant	LIG (a)	U.K. Generation	Total
2004 Revenue	$ -	$ -	$ -	$ 10	$ 165	$ 125	$ 300
2004 Pretax Income (Loss)	(3)	-	-	9	(12)	164	158
2004 Earnings (Loss), Net of Tax	(2)	-	-	6	(12)	91 (b)	83
2003 Revenue	-	-	58	60	653	125	896
2003 Pretax Income (Loss)	-	(20)	(23)	4	(122)	(713)	(874)
2003 Earnings (Loss), Net of Tax	16	(13)	(14)	5	(91)	(508) (c)	(605)
2002 Revenue	694	204	73	57	507	251	1,786
2002 Pretax Income (Loss)	180	(190)	(239)	(13)	14	(579)	(827)
2002 Earnings (Loss), Net of Tax	96	(123)	(156)	(7)	8	(472) (d)	(654)

(a) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC.
(b) Earnings per share related to the UK Operations was $0.23.
(c) Earnings per share related to the UK Operations was $(1.32).
(d) Earnings per share related to the UK Operations was $(1.42).

ASSET IMPAIRMENTS, INVESTMENT VALUE LOSSES AND OTHER RELATED CHARGES

In 2004, AEP recorded pretax impairments of assets (including goodwill) and investments totaling $18 million ($15 million related to Investment Value Losses, and $3 million related to charges recorded for Excess Real Estate in Maintenance and Other Operation in the Consolidated Statements of Operations) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit noncore businesses and other factors.

In 2003, AEP recorded pretax impairments of assets (including goodwill) and investments totaling $1.4 billion [consisting of approximately $650 million related to Asset Impairments of $610 million and Other Related Charges of $40 million, $70 million related to Investment Value Losses, $711 million related to Discontinued Operations ($550 million of impairments and $161 million of other charges) and $6 million related to charges recorded for Excess Real Estate in Maintenance and Other Operation in the Consolidated Statements of Operations] that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit noncore businesses and other factors.

In 2002, AEP recorded pretax impairments of assets (including goodwill) and investments totaling $1.7 billion (consisting of approximately $318 million related to Asset Impairments, $321 million related to Investment Value Losses, $938 million related to Discontinued Operations and $88 million related to charges recorded in other lines within the Consolidated Statements of Operations) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, and other factors. These impairments exclude the transitional goodwill impairment loss from adoption of SFAS 142 (see "Goodwill and Other Intangible Assets" section of Note 2).

The categories of impairments and gains on dispositions include:

	2004	2003	2002
		(in millions)	
Asset Impairments and Other Related Charges (Pretax)			
AEP Coal, Inc.	$ -	$ 67	$ 60
HPL and Other	-	315	-
Power Generation Facility	-	258	-
Blackhawk Coal Company	-	10	-
Ft. Davis Wind Farm	-	-	5
Texas Plants	-	-	38
Newgulf Facility	-	-	12
Excess Equipment	-	-	24
Nordic Trading	-	-	5
Excess Real Estate	-	-	16
Telecommunications – AEPC/C3	-	-	158
Total	$ -	$ 650	$ 318
Investment Value Losses (Pretax)			
Independent Power Producers	$ (2)	$ (70)	$ -
Bajio	(13)	-	-
Water Heater Assets	-	-	(3)
South Coast Power Investment	-	-	(63)
Telecommunications – AFN	-	-	(14)
AEP Gas Power Systems	-	-	(12)
Grupo Rede Investment – Vale	-	-	(217)
Technology Investments	-	-	(12)
Total	$ (15)	$ (70)	$ (321)
Gain on Disposition of Equity Investments, Net			
Independent Power Producers	$ 105	$ -	$ -
South Coast Power Investment	48	-	-
Total	$ 153	$ -	$ -
"Impairments and Other Related Charges" and "Operations" Included in Discontinued Operations (Net of tax)			
Impairments and Other Related Charges:			
U.K. Generation Plants	$ -	$ (375)	$ (414)
Louisiana Intrastate Gas (a)	-	(99)	-
CitiPower	-	-	(122)
Eastex	-	-	(142)
SEEBOARD	-	-	24
Pushan	-	-	(13)
Total (b)	$ -	$ (474)	$ (667)
Operations:			
U.K. Generation Plants	$ 91	$ (133)	$ (58)
Louisiana Intrastate Gas (a)	(12)	8	8
CitiPower	-	(13)	(1)
Eastex	-	(14)	(14)
SEEBOARD	(2)	16	72
Pushan	6	5	6
Total	$ 83	$ (131)	$ 13
Total Discontinued Operations	$ 83	$ (605)	$ (654)

(a) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC.
(b) See the "Dispositions" and "Discontinued Operations" sections of this note for the pretax impairment figures.

ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately $43 million, subject to closing adjustments, to an unrelated party. In May 2004, we received notice from the two nonaffiliated co-owners of the Oklaunion Power Station announcing their decision to exercise their right of first refusal with terms similar to the original agreement. In June 2004 and September 2004, we entered into sales agreements with both of our nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. One of these agreements is currently being challenged in Dallas County, Texas State District Court by the unrelated party with which we entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners' exercise of their rights of first refusal void. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on our future results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, in our Consolidated Balance Sheets as of December 31, 2004 and 2003.

Texas Plants – South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCC's 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal with terms similar to the original agreement. In September 2004, we entered into sales agreements with two of our nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. We do not expect the sale to have a significant effect on our future results of operations. We expect the sale to close in the first six months of 2005. TCC's assets and liabilities related to STP have been classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, in our Consolidated Balance Sheets as of December 31, 2004 and 2003.

The Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale at December 31, 2004 and 2003 are as follows:

December 31, 2004	**Texas Plants**
Assets:	**(in millions)**
Other Current Assets	$ 24
Property, Plant and Equipment, Net	413
Regulatory Assets	48
Nuclear Decommissioning Trust Fund	143
Total Assets of Discontinued Operations and Held for Sale	$ 628
Liabilities:	
Regulatory Liabilities	$ 1
Asset Retirement Obligations	249
Total Liabilities of Discontinued Operations and Held for Sale	$ 250

December 31, 2003	AEP Coal	Pushan Power Plant	LIG (excluding Jefferson Island)	Excess Real Estate	Jefferson Island	U.K. Generation	Texas Plants	Total
Assets:				(in millions)				
Current Risk Management Assets	$ -	$ -	$ -	$ -	$ -	$ 560	$ -	$ 560
Other Current Assets	6	24	49	-	1	685	57	822
Property, Plant and Equipment, Net	13	142	109	12	62	99	797	1,234
Regulatory Assets	-	-	-	-	-	-	49	49
Decommissioning Trusts	-	-	-	-	-	-	125	125
Goodwill	-	-	1	-	14	-	-	15
Long-term Risk Management Assets	-	-	-	-	-	274	-	274
Other	-	-	8	-	1	6	-	15
Total Assets of Discontinued Operations and Held for Sale	$ 19	$ 166	$ 167	$ 12	$ 78	$ 1,624	$ 1,028	$ 3,094
Liabilities:								
Current Risk Management Liabilities	$ -	$ -	$ 15	$ -	$ -	$ 767	$ -	$ 782
Other Current Liabilities	-	26	42	-	4	221	-	293
Long-term Debt	-	20	-	-	-	-	-	20
Long-term Risk Management Liabilities	-	-	-	-	-	435	-	435
Regulatory Liabilities	-	-	-	-	-	-	9	9
Asset Retirement Obligations	11	-	-	-	-	29	219	259
Employee Pension Obligations	-	-	-	-	-	12	-	12
Deferred Credits and Other	3	57	6	-	-	-	-	66
Total Liabilities of Discontinued Operations and Held for Sale	$ 14	$ 103	$ 63	$ -	$ 4	$ 1,464	$ 228	$ 1,876

ASSETS HELD AND USED

In 2003 and 2002, we recorded the following impairments related to assets held and used (including goodwill) to Asset Impairments and Other Related Charges on our Consolidated Statements of Operations as discussed below:

HPL and Other (Investments – Gas Operations segment)

HPL owns, or leases, and operates natural gas gathering, transportation and storage operations in Texas. In 2003, management announced that we were in the process of divesting our noncore assets, which includes the assets within our Investments-Gas Operations segment. During the fourth quarter of 2003, based on a probability-weighted, net of tax cash flow analysis of the fair value of HPL, we recorded a pretax impairment of $300 million ($218 million net of tax). This impairment included a pretax impairment of $150 million related to goodwill, reflecting management's decision not to operate HPL as a major trading hub. The cash flow analysis used management's estimate of the alternative likely outcomes of the uncertainties surrounding the continued use of the Bammel facility and other matters (see "Enron Bankruptcy" section of Note 7) and a net of tax risk free discount rate of 3.3% over the remaining life of the assets.

We also recorded a pretax charge of $15 million ($10 million net of tax) in the fourth quarter of 2003. This impairment is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. This charge related to the effect of the write-off of certain HPL and LIG assets and the impairment of goodwill related to our former optimization strategy of LIG assets by AEP Energy Services.

The total HPL pretax impairment of $315 million in 2003 is included in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

See Note 19 for additional discussion of the sale of HPL in 2005.

Blackhawk Coal Company (Utility Operations segment)

Blackhawk Coal Company (Blackhawk) is a wholly-owned subsidiary of I&M and was formerly engaged in coal mining operations until they ceased due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the carrying value of the investment was impaired based on an updated valuation reflecting management's decision not to pursue development of potential gas reserves. As a result, a pretax charge of $10 million was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

Power Generation Facility (Investments – Other segment)

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. Juniper will own the Facility and lease it to AEP after construction is completed and we will sublease the Facility to The Dow Chemical Company.

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation. In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded $496 million of construction work in progress and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2004 and 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since Juniper's funded obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the table of future minimum lease payments in Note 16.

The uncertainty of the litigation between Tractebel Energy Marketing, Inc. (TEM) and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power freed up by TEM contract termination, triggered us to review the project for possible impairment of its reported values. We determined that the value of the Facility was impaired and recorded a pretax impairment of $258 million ($168 million net of tax) in December 2003. The impairment was recorded to Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

See further discussion in "Power Generation Facility" section of Note 7.

OTHER LOSSES

<u>2004</u>

Compresion Bajio S de R.L. de C.V. (Investments – Other segment)

In January 2002, we acquired a 50% interest in Compresion Bajio S de R.L. de C.V. (Bajio), a 600-megawatt power plant in Mexico. Due to the decision to divest noncore assets, we began marketing our investment in Bajio to potential buyers in the third quarter of 2003.

In December 2004, on the basis of an indicative bid by a prospective buyer, an estimated pretax other than temporary impairment of $13 million was recorded for Bajio and classified in Investment Value Losses on our Consolidated Statements of Operations.

<u>2002</u>

Telecommunications (Investments – Other segment)

We developed businesses to provide telecommunication services to businesses and other telecommunication companies through broadband fiber optic networks. The businesses included AEP Communications, LLC (AEPC), C3 Communications, Inc. (C3), and a 50% share of AFN, LLC (AFN), a joint venture. Due to the difficult economic conditions in these businesses and the overall telecommunications industry, the AEP Board approved in December 2002 a plan to cease operations of these businesses. We took steps to market the assets of the businesses to potential interested buyers in the fourth quarter of 2002.

We completed the sale of substantially all the assets of C3 in the first quarter of 2003 as discussed in the "Dispositions" section of this note. AFN closed on the sale of substantially all of its assets in January 2004 with no significant additional effect on results of operations in 2004. The sale of remaining telecommunication assets is proceeding.

An estimated pretax impairment loss of $158 million ($76 million related to AEPC and $82 million related to C3) was recorded in December 2002 and is classified in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations. An estimated pretax loss in value of the investment in AFN of $14 million was recorded in December 2002 and is classified in Investment Value Losses in our Consolidated Statements of Operations. The estimated losses were based on indicative bids by potential buyers.

Technology Investments (Investments – Other segment)

We previously made investments totaling $12 million in four early-stage or startup technologies involving pollution control and procurement. An analysis in December 2002 of the viability of the underlying technologies and the projected performance of the investee companies indicated that the investments were unlikely to be recovered, and an other than temporary impairment of the entire amount of the equity interest under APB 18, "The Equity Method of Accounting for Investments in Common Stock," was recorded. The loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations.

11. BENEFIT PLANS

In the U.S. we sponsor two qualified pension plans and two nonqualified pension plans. A substantial majority of our employees in the U.S. are covered by either one qualified plan or both a qualified and a nonqualified pension plan. Other postretirement benefit plans are sponsored by us to provide medical and life insurance benefits for retired employees in the U.S. We implemented FSP FAS 106-2 in the second quarter of 2004, retroactive to the first quarter of 2004 (see "FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003" section of Note 2). The Medicare subsidy reduced our FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million contributing to an actuarial gain in 2004. The tax-free subsidy reduced 2004's net periodic postretirement benefit cost by a total of $29 million, including $12 million of amortization of the actuarial gain, $4 million of reduced service cost, and $13 million of reduced interest cost on the APBO.

We also had a foreign pension plan for employees of AEP Energy Services UK Generation Limited (Genco) in the U.K. The Genco pension plan had $7 million of accumulated benefit obligations in excess of plan assets at December 31, 2002. The plan was in an overfunded position at December 31, 2003. The plan was transferred in 2004 in conjunction with the sale of the U.K. generation assets.

The following tables provide a reconciliation of the changes in the plans' projected benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2004, and a statement of the funded status as of December 31 for both years:

Projected Pension Obligations, Plan Assets, Funded Status as of December 31, 2004 and 2003:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in millions)			
Change in Projected Benefit Obligation:				
Projected Obligation at January 1	$ 3,688	$ 3,583	$ 2,163	$ 1,877
Service Cost	86	80	41	42
Interest Cost	228	233	117	130
Participant Contributions	-	-	18	14
Actuarial (Gain) Loss	379	91	(130)	192
Benefit Payments	(273)	(299)	(109)	(92)
Projected Obligation at December 31	$ 4,108	$ 3,688	$ 2,100	$ 2,163
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$ 3,180	$ 2,795	$ 950	$ 723
Actual Return on Plan Assets	409	619	98	122
Company Contributions (a)	239	65	136	183
Participant Contributions	-	-	18	14
Benefit Payments (a)	(273)	(299)	(109)	(92)
Fair Value of Plan Assets at December 31	$ 3,555	$ 3,180	$ 1,093	$ 950
Funded Status:				
Funded Status at December 31	$ (553)	$ (508)	$ (1,007)	$ (1,213)
Unrecognized Net Transition Obligation	-	2	179	206
Unrecognized Prior Service Cost (Benefit)	(9)	(12)	5	6
Unrecognized Net Actuarial Loss	1,040	797	795	977
Net Asset (Liability) Recognized	$ 478	$ 279	$ (28)	$ (24)

(a) Our contributions and benefit payments include only those amounts contributed directly to or paid directly from plan assets.

Amounts Recognized in the Balance Sheet as of December 31, 2004 and 2003:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in millions)			
Prepaid Benefit Costs	$ 524(a)	$ 325	$ -	$ -
Accrued Benefit Liability	(46)	(46)	(28)	(24)
Additional Minimum Liability	(566)	(723)	N/A	N/A
Intangible Asset	36	39	N/A	N/A
Pretax Accumulated Other Comprehensive Income	530	684	N/A	N/A
Net Asset (Liability) Recognized	$ 478	$ 279	$ (28)	$ (24)

N/A = Not Applicable

(a) Includes $386 million related to the qualified plan that became fully funded upon receipt of the December 2004 discretionary contribution.

Pension and Other Postretirement Plans' Assets:

The asset allocations for our pension plans at the end of 2004 and 2003, and the target allocation for 2005, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2005	**2004**	**2003**
Asset Category		**(in percentage)**	
Equity Securities	70	68	71
Debt Securities	28	25	27
Cash and Cash Equivalents	2	7	2
Total	100	100	100

The asset allocations for our other postretirement benefit plans at the end of 2004 and 2003, and target allocation for 2005, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2005	**2004**	**2003**
Asset Category		**(in percentage)**	
Equity Securities	70	70	61
Debt Securities	28	28	36
Other	2	2	3
Total	100	100	100

Our investment strategy for our employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk. We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. Because of a $200 million discretionary contribution at the end of 2004, the actual pension asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2005.

The value of our pension plans' assets increased to $3.6 billion at December 31, 2004 from $3.2 billion at December 31, 2003. The qualified plans paid $265 million in benefits to plan participants during 2004 (nonqualified plans paid $8 million in benefits).

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:	**2004**	**2003**
	(in millions)	
Qualified Pension Plans	$ 3,918	$ 3,549
Nonqualified Pension Plans	80	76
Total	$ 3,998	$ 3,625

Minimum Pension Liability:

Our combined pension funds are underfunded in total (plan assets are less than projected benefit obligations) by $553 million at December 31, 2004. 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, 2004 and 2003 were as follows:

End of Year	Underfunded Pension Plans 2004	Underfunded Pension Plans 2003
	(in millions)	
Projected Benefit Obligation	$ 2,978	$ 3,688
Accumulated Benefit Obligation	2,880	3,625
Fair Value of Plan Assets	2,406	3,180
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	474	445

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2004 and 2003, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability 2004	Decrease in Minimum Pension Liability 2003
	(in millions)	
Other Comprehensive Income	$ (92)	$ (154)
Deferred Income Taxes	(52)	(75)
Intangible Asset	(3)	(5)
Other	(10)	13
Minimum Pension Liability	$ (157)	$ (221)

We made an additional discretionary contribution of $200 million in the fourth quarter of 2004 and intend to make additional discretionary contributions of approximately $100 million per quarter in 2005 to meet our goal of fully funding all qualified pension plans by the end of 2005.

Actuarial Assumptions for Benefit Obligations:

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

	Pension Plans 2004	Pension Plans 2003	Other Postretirement Benefit Plans 2004	Other Postretirement Benefit Plans 2003
	(in percentages)			
Discount Rate	5.50	6.25	5.80	6.25
Rate of Compensation Increase	3.70	3.70	N/A	N/A

The method used to determine the discount rate that we utilize for determining future benefit obligations was revised in 2004. Historically, it has been based on the Moody's AA bond index which includes long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis was 6.25% at December 31, 2003 and would have been 5.75% at December 31, 2004. In 2004, we changed to 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 was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2004 under this method was 5.50% for pension plans and 5.80% for other postretirement benefit plans.

The rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 8.5% per year, with an average increase of 3.7%.

Estimated Future Benefit Payments and Contributions:

Information about the expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

Employer Contributions	Pension Plans 2005	Pension Plans 2004	Other Postretirement Benefit Plans 2005	Other Postretirement Benefit Plans 2004
	(in millions)			
Required Contributions (a)	$17	$31	N/A	N/A
Additional Discretionary Contributions	400 (b)	200 (b)	$142	$137

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor.
(b) Contribution in 2004 and expected contribution in 2005 in excess of the required contribution to fully fund our qualified pension plans by the end of 2005.

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater, plus the additional discretionary contributions to fully fund the qualified pension plans. The contribution to the other postretirement benefit plans' trust is generally based on the amount of the other postretirement benefit plans' expense for accounting purposes and is provided for in agreements with state regulatory authorities.

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. 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 other postretirement benefits are as follows:

	Pension Plans: Pension Payments	Other Postretirement Benefit Plans: Benefit Payments	Other Postretirement Benefit Plans: Medicare Subsidy Receipts
		(in millions)	
2005	$ 293	$ 115	$ -
2006	302	122	(9)
2007	317	131	(10)
2008	327	140	(11)
2009	348	151	(12)
Years 2010 to 2014, in Total	1,847	867	(72)

Components of Net Periodic Benefit Cost:

The following table provides the components of our net periodic benefit cost (credit) for the plans for fiscal years 2004, 2003 and 2002:

	Pension Plans			Other Postretirement Benefit Plans		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**
			(in millions)			
Service Cost	$ 86	$ 80	$ 72	$ 41	$ 42	$ 34
Interest Cost	228	233	241	117	130	114
Expected Return on Plan Assets	(292)	(318)	(337)	(81)	(64)	(62)
Amortization of Transition (Asset) Obligation	2	(8)	(9)	28	28	29
Amortization of Prior Service Cost	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial (Gain) Loss	17	11	(10)	36	52	27
Net Periodic Benefit Cost (Credit)	40	(3)	(44)	141	188	142
Capitalized Portion	(10)	(3)	15	(46)	(43)	(26)
Net Periodic Benefit Cost (Credit) Recognized as Expense	$ 30	$ (6)	$ (29)	$ 95	$ 145	$ 116

Actuarial Assumptions for Net Periodic Benefit Costs:

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

	Pension Plans			Other Postretirement Benefit Plans		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**
			(in percentage)			
Discount Rate	6.25	6.75	7.25	6.25	6.75	7.25
Expected Return on Plan Assets	8.75	9.00	9.00	8.35	8.75	8.75
Rate of Compensation Increase	3.70	3.70	3.70	N/A	N/A	N/A

The expected return on plan assets for 2004 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was reduced to 8.35%.

The health care trend rate assumptions used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates:	**2004**	**2003**
Initial	10.0%	10.0%
Ultimate	5.0%	5.0%
Year Ultimate Reached	2009	2008

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 27	$ (21)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	302	(245)

AEP Savings Plans

We sponsor various defined contribution retirement savings plans eligible to substantially all non-United Mine Workers of America (UMWA) U.S. employees. These plans include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. On January 1, 2003, the two major AEP Savings Plans merged into a single plan. Our contributions to the plan are 75% of the first 6% of eligible employee compensation. The cost for contributions to these plans totaled $55.0 million in 2004, $57.0 million in 2003 and $60.1 million in 2002.

Other 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 are expensed as paid as part of the cost of active mining operations and were not material in 2004, 2003 and 2002.

12. STOCK-BASED COMPENSATION

The American Electric Power System 2000 Long-Term Incentive Plan (the Plan) authorizes the use of 15,700,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. The Plan was adopted in 2000 by the Board of Directors and shareholders.

Stock-based compensation awards granted by AEP include restricted stock units, restricted shares, performance share units and stock options. Restricted stock units generally vest, subject to the participant's continued employment, in approximately equal 1/3 or 1/5 increments on each of the first three or five anniversaries of the grant date. Amounts equivalent to dividends paid on AEP shares accrue as additional restricted stock units that vest on the last vesting date associated with the underlying units. AEP awarded 105,852 and 105,910 restricted stock units, including units awarded for dividends, with weighted-average grant-date fair values of $32.03 and $22.17 per unit in 2004 and 2003, respectively. Restricted stock units were not granted prior to 2003. Compensation cost is recorded over the vesting period based on the market value on the grant date. Expense associated with units that are forfeited is reversed in the period of forfeiture.

AEP awarded 300,000 restricted shares in 2004, which vest over periods ranging from 1 to 8 years. Compensation cost is recorded over the vesting period based on the market value of $30.76 per unit on the grant date. Restricted shares were not granted prior to 2004.

Performance share units are equal in value to shares of AEP common stock but are subject to an attached performance factor ranging from 0% to 200%. The performance factor is determined at the end of the performance period based on performance measure(s) established for each grant at the beginning of the performance period by the Human Resources Committee of the Board of Directors. Performance share units are typically paid in cash at the end of a three-year vesting period, unless they are needed to satisfy a participant's stock ownership requirement, in which case they are mandatorily deferred as phantom stock units until the end of the participant's AEP career. Phantom stock units have a value equivalent to AEP common stock and are typically paid in cash upon the participant's termination of employment. AEP awarded 171,270, 1,103,542 and 167,040 performance share units, including units awarded for dividends on other units, with weighted-average grant-date fair values of $31.42, $27.94 and $42.14 per unit in 2004, 2003 and 2002, respectively. In 2004 and 2003, no performance share units were deferred into phantom stock units to satisfy stock ownership requirements. However, AEP awarded 8,809 and 14,042 additional phantom stock units as dividends on other units with weighted-average grant-date fair values of $32.92 and $25.60 per unit in 2004 and 2003, respectively. In 2002, 42,115 performance share units were deferred into phantom stock units to satisfy stock ownership requirements and 15,388 phantom stock units with a weighted-average grant-date fair value of $34.20 per unit were awarded as dividends on other units. The compensation cost for performance share units is recorded over the vesting period, and the liability for both the performance share and phantom stock unit is adjusted for changes in fair market value. Amounts equivalent to cash dividends on both performance share and phantom stock units accrue as additional units.

Under the Plan, the exercise price of all stock option grants must equal or exceed the market price of AEP's common stock on the date of grant, and in accordance with its policy, AEP does not record compensation expense. AEP does, however, anticipate adopting SFAS 123R effective July 1, 2005 which will result in the recording of compensation expense for stock options (see "SFAS 123R" in Note 2). AEP historically has granted options that have a ten-year life and vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1 following the first, second and third anniversary of the grant date.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. Outstanding CSW stock options will continue in effect until all options are exercised, cancelled or expired. Under the CSW stock option plan, the option price was equal to the fair market value of the stock on the grant date. All CSW options fully vested upon the completion of the merger and expire 10 years after their original grant date.

A summary of AEP stock option transactions in fiscal years 2004, 2003 and 2002 is as follows:

	2004		2003		2002	
	Options (in thousands)	**Weighted Average Exercise Price**	**Options (in thousands)**	**Weighted Average Exercise Price**	**Options (in thousands)**	**Weighted Average Exercise Price**
Outstanding at beginning of year	9,095	$ 33	8,787	$ 34	6,822	$ 37
Granted	149	$ 31	928	$ 28	2,923	$ 27
Exercised	(525)	$ 27	(23)	$ 27	(600)	$ 36
Forfeited	(489)	$ 34	(597)	$ 33	(358)	$ 41
Outstanding at end of year	8,230	$ 33	9,095	$ 33	8,787	34
Options exercisable at end of year	6,069	$ 35	3,909	$ 36	2,481	$ 36
Weighted average exercise price of options:						
Granted above Market Price		N/A		N/A		$ 27
Granted at Market Price		$ 31		$ 28		$ 27

The following table summarizes information about AEP stock options outstanding at December 31, 2004:

Options Outstanding

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life	Weighted Average Exercise Price
	(in thousands)	(in years)	
\$25.73 - \$27.95	2,833	7.3	\$ 27.30
\$30.76 - \$35.63	4,905	4.9	35.47
\$43.79 - \$49.00	492	6.4	46.05
	8,230	5.8	33.29

Options Exercisable

Range of Exercise Prices	Number Outstanding	Weighted Average Exercise Price
	(in thousands)	
\$25.73 - \$27.95	914	\$ 27.11
\$30.76 - \$35.63	4,756	35.62
\$43.79 - \$49.00	399	46.42
	6,069	35.05

The proceeds received from exercised stock options are included in common stock and paid-in capital.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions used to estimate the fair value of AEP options granted:

	2004	2003	2002
Risk Free Interest Rate	4.14%	3.92%	3.53%
Expected Life	7 years	7 years	7 years
Expected Volatility	28.17%	27.57%	29.78%
Expected Dividend Yield	4.84%	4.86%	6.15%
Weighted average fair value of options:			
Granted above Market Price	N/A	N/A	\$ 4.58
Granted at Market Price	\$ 6.06	\$ 5.26	\$ 4.37

13. BUSINESS SEGMENTS

We identified our reportable segments based on the nature of the product and services and geography. Our core operations involve domestic utility operations, including generation, transmission and distribution of electric energy. Certain Investments segments are reported by product or service (Gas Operations and Other) while our Investments – UK Operations segment is distinguished by its geography. These operating segments are not aggregated.

In addition to our business operations with external customers, our business segments also provide products and services between business segments. These intersegment activities primarily consist of risk management activities and barging activities performed by our Utility Operations segment and the sale of gas by our Investments – Gas Operations segment. Our Investments – Other segment provides accounts receivable factoring, barging activities and until the second quarter of 2004, the sale of coal to our Utility Operations segment. Our All Other segment includes items such as interest related to financing costs, litigation costs on behalf of other segments and other corporate-type services.

Our current international portfolio, presented in our Investments – Other segment, includes only limited investments in the generation and supply of power in Mexico and the Pacific Rim. We sold our generation assets in the U.K. and China in 2004. In 2002, we sold our investments in international distribution companies in Australia and the U.K.

Our segments and their related business activities are as follows:

Utility Operations

- Domestic generation of electricity for sale to retail and wholesale customers
- Domestic electricity transmission and distribution

Investments - Gas Operations (a)

- Gas and pipeline and storage services

Investments - UK Operations (b)

- International generation of electricity for sale to wholesale customers
- Coal procurement and transportation to AEP's U.K. plants

Investments – Other (c)

- Bulk commodity barging operations, wind farms, independent power producers and other energy supply businesses

(a) Operations of LIG Pipeline Company and its subsidiaries, including Jefferson Island Storage & Hub LLC, were classified as discontinued during 2003 and were sold during 2004. The remaining gas assets were sold during the first quarter of 2005.
(b) UK Operations were classified as discontinued during 2003 and were sold during 2004.
(c) Four independent power producers were sold during 2004.

The tables below present segment income statement information for the twelve months ended December 31, 2004, 2003 and 2002 and balance sheet information for the years ended December 31, 2004 and 2003. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

2004	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 10,513	$ 3,064	$ -	$ 480	$ -	$ -	$ 14,057
Other Operating Segments	120	50	-	80	7	(257)	-
Total Revenues	$ 10,633	$ 3,114	$ -	$ 560	$ 7	$ (257)	$ 14,057
Income (Loss) Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes	$ 1,171	$ (51)	$ -	$ 78	$ (71)	$ -	$ 1,127
Discontinued Operations, Net of Tax	-	(12)	91	4	-	-	83
Extraordinary Item, Net of Tax	(121)	-	-	-	-	-	(121)
Net Income (Loss)	$ 1,050	$ (63)	$ 91	$ 82	$ (71)	$ -	$ 1,089
Depreciation and Amortization Expense	$ 1,256	$ 11	$ -	$ 32	$ 1	$ -	$ 1,300
Gross Property Additions	1,527	132	-	34	-	-	1,693
As of December 31, 2004							
Total Assets	$ 32,281	$ 1,801	$ 221 (c)	$ 1,345	$ 10,158	$ (11,143)	$ 34,663
Assets Held for Sale	628	-	-	-	-	-	628
Investments in Equity Method Subsidiaries	-	33	-	117	-	-	150

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.

(b) 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.

(c) Total Assets of $221 million for the Investments-UK Operations segment include $124 million in affiliated accounts receivable that are eliminated in consolidation. The majority of the remaining $97 million in assets represents cash equivalents and third party receivables.

2003	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other (a)	Reconciling Adjustments (b)	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 10,869	$ 3,099	$ -	$ 699	$ -	$ -	$ 14,667
Other Operating Segments	146	27	-	94	11	(278)	-
Total Revenues	$ 11,015	$ 3,126	$ -	$ 793	$ 11	$ (278)	$ 14,667
Income (Loss) Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes	$ 1,219	$ (290)	$ -	$ (278)	$ (129)	$ -	$ 522
Discontinued Operations, Net of Tax	-	(91)	(508)	(6)	-	-	(605)
Cumulative Effect of Accounting Changes, Net of Tax	236	(22)	(21)	-	-	-	193
Net Income (Loss)	$ 1,455	$ (403)	$ (529)	$ (284)	$ (129)	$ -	$ 110
Depreciation and Amortization Expense	$ 1,250	$ 18	$ -	$ 39	$ -	$ -	$ 1,307
Gross Property Additions	1,323	25	-	10	-	-	1,358
As of December 31, 2003							
Total Assets	$ 30,829	$ 2,494	$ 1,662	$ 1,738	$ 13,604	$ (13,546)	$ 36,781
Assets Held for Sale	1,028	245	1,624	185	12	-	3,094
Investments in Equity Method Subsidiaries	-	36	-	156	-	-	192

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.
(b) 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.

2002	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 10,446	$ 2,071	$ -	$ 910	$ -	$ -	$ 13,427
Other Operating Segments	45	212	-	149	-	(406)	-
Total Revenues	$ 10,491	$ 2,283	$ -	$ 1,059	$ -	$ (406)	$ 13,427
Income (Loss) Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes	$ 1,154	$ (99)	$ -	$ (522)	$ (48)	$ -	$ 485
Discontinued Operations, Net of Tax	-	8	(472)	(190)	-	-	(654)
Cumulative Effect of Accounting Changes, Net of Tax	-	-	-	(350)	-	-	(350)
Net Income (Loss)	$ 1,154	$ (91)	$ (472)	$ (1,062)	$ (48)	$ -	$ (519)
Depreciation and Amortization Expense	$ 1,276	$ 13	$ -	$ 67	$ -	$ -	$ 1,356
Gross Property Additions	1,517	47	-	25	96	-	1,685

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.

14. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. However, energy markets are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

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. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Contracts that have been designated as normal purchase or normal sale under SFAS 133 are not considered derivatives and are recognized on the accrual or settlement basis.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on if 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 in the Consolidated Statements of Operations. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses in the Consolidated Statements of Operations depending on the relevant facts and circumstances.

We designate the hedging instrument, based on the exposure being hedged, as a fair value hedge, a cash flow hedge or a hedge of a net investment in a foreign operation. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Revenues in the Consolidated Statements of Operations during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) and subsequently reclassify it to Revenues in the Consolidated Statements of Operations when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in Revenues during the period of change. For a hedge of a net investment in a foreign currency, we include the effective portion of the gain or loss in Accumulated Other Comprehensive Income as part of the cumulative translation adjustment. We recognize any ineffective portion of the gain or loss in Revenues immediately during the period of change.

Fair Value Hedging Strategies

We enter into natural gas forward and swap transactions to hedge natural gas inventory. The purpose of the hedging activity was to protect the natural gas inventory against changes in fair value due to changes in the spot gas prices. The derivative contracts designated as fair value hedges of our natural gas inventory were MTM each month based upon changes in the NYMEX forward prices, whereas the natural gas inventory was MTM on a monthly basis based upon changes in the Gas Daily spot price at the end of the month. The differences between the indices used to MTM the natural gas inventory and the forward contracts designated as fair value hedges can result in volatility in our reported net income. However, over time gains or losses on the sale of the natural gas inventory will be offset by gains or losses on the fair value hedges, resulting in the realization of gross margin the Company anticipated at the time the transaction was structured. In the third quarter of 2004, the fair value hedges were de-designated, as a result the existing hedged inventory was held at the market price on the fair value hedge de-designation date with subsequent additions to inventory carried at cost. During the years ended December 31, 2004 and 2003, we recognized a pretax loss of approximately \$(27.0) million and \$(3.4) million, respectively, within revenues related to hedge ineffectiveness and changes in time value excluded from the assessment of hedge ineffectiveness.

We enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. The interest rate forward and swap transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. We do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

We enter into forward contracts to protect against the reduction in value of forecasted cash flows resulting from transactions denominated in foreign currencies. When the dollar strengthens significantly against the foreign currencies, the decline in value of future foreign currency revenue is offset by gains in the value of the forward contracts designated as cash flow hedges. Conversely, when the dollar weakens, the increase in the value of future foreign currency cash flows is offset by losses in the value of forward contracts. We do not hedge all foreign currency exposure.

We enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. These transactions effectively modify our exposure to interest risk by converting a portion of our floating-rate debt to a fixed rate. During 2004, we also entered into various forward starting interest rate swap contracts to manage the interest rate exposure on anticipated borrowings of fixed-rate debt through the second quarter of 2005. The anticipated debt offerings have a high probability of occurrence because the proceeds will be utilized to fund existing debt maturities as well as fund projected capital expenditures. We do not hedge all interest rate exposure. During 2004, we reclassified an immaterial amount to earnings because the original forecasted transaction did not occur within the originally specified time period.

We enter into, and designate as cash flow hedges, certain forward and swap transactions for the purchase and sale of electricity and natural gas to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into contracts to protect margins for a portion of future sales and generation revenues. We do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity. During 2004, we classified an immaterial amount into earnings as a result of hedge ineffectiveness related to our cash flow hedging strategies.

We enter into natural gas futures contracts to protect against the reduction in value of forecasted cash flows resulting from spot purchases and sales of natural gas at Houston Ship Channel (HSC). We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into contracts to protect margins for a portion of future spot purchases and sales. We do not hedge all variable price risk exposure related to the forecasted spot purchase and sale of natural gas. The amount of hedges' ineffectiveness was immaterial during 2004.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets at December 31, 2004 are:

	Hedging Assets	Hedging Liabilities	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings during the Next 12 Months
		(in millions)		
Power and Gas	$ 88	$ (60)	$ 23	$ (26)
Interest Rate	1	(23)	(23)(a)	4
Foreign Currency	-	-	-	-
	$ 89	$ (83)	$ -	$ (22)

(a) Includes $3 million loss recorded in an equity investment.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets at December 31, 2003 are:

	Hedging Assets	Hedging Liabilities	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings during the Next 12 Months
		(in millions)		
Power and Gas	$ 21	$ (121)	$ (65)	$ (58)
Interest Rate	-	(7)	(9)(a)	(8)
Foreign Currency	-	(30)	20	(20)
	$ 21	$ (158)	$ (94)	$ (86)

(a) Includes $6 million loss recorded in an equity investment.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of December 31, 2004 and 2003, fourteen months and 5 years, respectively are the maximum lengths of time that we are hedging, with SFAS 133 designated contracts, our exposure to variability in future cash flows for forecasted transactions.

The following table represents the activity in Accumulated Comprehensive Other Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2004:

	Amount (in millions)
Beginning Balance, December 31, 2001	$ (3)
Changes in fair value	(56)
Reclasses from AOCI to net earnings	43
Balance at December 31, 2002	(16)
Changes in fair value	(79)
Reclasses from AOCI to net earnings	1
Balance at December 31, 2003	(94)
Changes in fair value	8
Reclasses from AOCI to net earnings	86
Ending Balance, December 31, 2004	$ -

Hedge of Net Investment in Foreign Operations

In 2002, we used foreign denominated fixed-rate debt to protect the value of our investments in foreign subsidiaries in the U.K. Realized gains and losses from these hedges are not included in the income statement, but are shown in the cumulative translation adjustment account included in Accumulated Other Comprehensive Income (Loss).

During 2002, we recognized $64 million of net losses, included in the cumulative translation adjustment, related to the foreign denominated fixed-rate debt.

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or 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 significant financial instruments at December 31, 2004 and 2003 are summarized in the following tables.

	2004		2003	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 12,287	$ 12,813	$ 14,101	$ 14,621
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	66	67	76	76

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments which are classified as available for sale for decommissioning and SNF disposal, reported in "Spent Nuclear Fuel and Decommissioning Trusts" and "Assets of Discontinued Operations and Held for Sale" on our Consolidated Balance Sheets, are recorded at market value in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." At December 31, 2004 and 2003, the fair values of the trust investments were $1.2 billion and $1.1 billion, respectively, and had a cost basis of $1.0 billion and $1.0 billion, respectively. The change in market value in 2004, 2003 and 2002 was a net unrealized gain of $41 million and $53 million and a net unrealized loss of $33 million, respectively.

15. INCOME TAXES

The details of our consolidated income taxes before discontinued operations, extraordinary item and cumulative effect of accounting changes as reported are as follows:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
Federal:			
Current	$ 262	$ 297	$ 307
Deferred	263	34	(60)
Total	525	331	247
State and Local:			
Current	49	19	32
Deferred	(3)	1	28
Total	46	20	60
International:			
Current	1	7	8
Deferred	-	-	-
Total	1	7	8
Total Income Tax as Reported Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes	$ 572	$ 358	$ 315

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.

	Year Ended December 31, 2004	2003	2002
		(in millions)	
Net Income (Loss)	$ 1,089	$ 110	$ (519)
Discontinued Operations (net of income tax of $75 million, $(312) million and $(174) million in 2004, 2003 and 2002, respectively)	(83)	605	654
Extraordinary Loss on Texas Stranded Cost Recovery, (net of income tax of $(64) million in 2004)	121	-	-
Cumulative Effect of Accounting Changes (net of income tax of $138 million and $0 in 2003 and 2002, respectively)	-	(193)	350
Preferred Stock Dividends	6	9	11
Income Before Preferred Stock Dividends of Subsidiaries	1,133	531	496
Income Taxes Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes	572	358	315
Pretax Income	$ 1,705	$ 889	$ 811
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 597	$ 311	$ 284
Increase (Decrease) in Income Taxes resulting from the following Items:			
Depreciation	36	34	32
Asset Impairments and Investment Value Losses	-	23	4
Investment Tax Credits (net)	(29)	(33)	(35)
Tax Effects of International Operations	1	8	27
Energy Production Credits	(16)	(15)	(14)
State Income Taxes	30	13	39
Other	(47)	17	(22)
Total Income Taxes as Reported Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes	$ 572	$ 358	$ 315
Effective Income Tax Rate	33.5%	40.3%	38.8%

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

	As of December 31, 2004	2003
	(in millions)	
Deferred Tax Assets	$ 2,280	$ 3,354
Deferred Tax Liabilities	(7,099)	(7,311)
Net Deferred Tax Liabilities	(4,819)	(3,957)
Property Related Temporary Differences	$ (3,273)	$ (2,850)
Amounts Due From Customers For Future Federal Income Taxes	(184)	(180)
Deferred State Income Taxes	(452)	(416)
Transition Regulatory Assets	(211)	(254)
Securitized Transition Assets	(258)	(281)
Regulatory Assets	(578)	(195)
Deferred Income Taxes on Other Comprehensive Loss	186	306
All Other (net)	(49)	(87)
Net Deferred Tax Liabilities	$ (4,819)	$ (3,957)

The IRS and other taxing authorities routinely examine our tax returns. Management believes that we have filed tax returns with positions that may be challenged by these tax authorities. These positions relate to, among others, the federal treatment of taxes paid to foreign taxing authorities (the most significant of which is the federal treatment of the U.K. Windfall Profits Tax), the timing and amount of deductions and the tax treatment related to acquisitions and divestitures. We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. We have received Revenue Agent's Reports from the IRS for the years 1991 through 1999, and have filed protests contesting certain proposed adjustments. CSW, which was a separate consolidated group prior to its merger with AEP, is currently being audited for the years 1997 through the date of merger in June 2000. Returns for the years 2000 through 2003 are presently being audited by the IRS.

Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As of December 31, 2004, the Company has total provisions for uncertain tax positions of approximately $144 million. In addition, the Company accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

We join in the filing of a consolidated federal income tax return with our affiliated companies in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

16. 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 operating expenses 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:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
Lease Payments on Operating Leases	$ 317	$ 344	$ 359
Amortization of Capital Leases	54	64	65
Interest on Capital Leases	11	9	14
Total Lease Rental Costs	$ 382	$ 417	$ 438

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31, 2004	December 31, 2003
	(in millions)	
Property, Plant and Equipment Under Capital Leases:		
Production	$ 91	$ 37
Distribution	15	15
Other	323	470
Total Property, Plant and Equipment	429	522
Accumulated Amortization	186	218
Net Property, Plant and Equipment Under Capital Leases	$ 243	$ 304
Obligations Under Capital Leases:		
Noncurrent Liability	$ 190	$ 131
Liability Due Within One Year	53	51
Total Obligations under Capital Leases	$ 243	$ 182

Future minimum lease payments consisted of the following at December 31, 2004:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2005	$ 64	$ 291
2006	55	259
2007	42	246
2008	30	231
2009	21	221
Later Years	92	2,181
Total Future Minimum Lease Payments	$ 304	$ 3,429
Less Estimated Interest Element	61	
Estimated Present Value of Future Minimum Lease Payments	$ 243	

Gavin Scrubber Financing Arrangement

In 1994, OPCo entered into an agreement with JMG, an unrelated special purpose entity. JMG was formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. JMG owns the Gavin Scrubber and previously leased it to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($470 million). Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for as an operating lease. For 2002 and the first half of 2003, operating lease payments related to the Gavin Scrubber were recorded as operating lease expense by OPCo. After July 1, 2003, OPCo records the depreciation, interest and other operating expenses of JMG and eliminates JMG's rental revenues against OPCo's operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of the requirement to consolidate JMG and there was no change in net income due to the consolidation of JMG. The debt obligations of JMG are now included in long-term debt as Notes Payable and Installment Purchase Contracts and are excluded from the above table of future minimum lease payments.

At any time during the obligation, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber on behalf of JMG. The initial 15-year term is noncancelable. At the end of the initial term, OPCo can renew the obligation, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In the case of a sale at less than the adjusted acquisition cost, OPCo is required pay the difference to JMG.

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 future minimum lease payments for each respective company as of December 31, 2004 are $1.3 billion.

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. 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.

Railcar Lease

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms, for a maximum of twenty years. We intend to renew the lease for the full twenty years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease with the future payments included in the future minimum lease payments schedule earlier in this note. This operating lease agreement allows us to avoid a large initial capital expenditure, and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the term from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2004, the maximum potential loss was approximately $32 million ($21 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year to a nonaffiliated company under an operating lease. The sublessee may renew the lease for up to three additional one-year terms. AEP has other rail car lease arrangements that do not utilize this type of structure.

17. FINANCING ACTIVITIES

Dividend Restrictions

Under PUHCA, AEP and its public utility subsidiaries can only pay dividends out of retained or current earnings.

Trust Preferred Securities

SWEPCo has a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46. The trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on the Balance Sheet. The investment in the trust is reported as Other within Other Noncurrent Assets while the Junior Subordinated Debentures are reported as Notes Payable to Trust within Long-term Debt.

In October 2003, SWEPCo refinanced its Junior Subordinated Debentures which are due October 1, 2043. Junior Subordinated Debentures were retired in the second quarter of 2004 for PSO and in the third quarter of 2004 for TCC. The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2004 and 2003:

Business Trust	Security	Units Issued/ Outstanding at 12/31/04	Amount in Other at 12/31/04 (a)	Amount in Notes Payable to Trust at 12/31/04 (b)	Amount in Other at 12/31/03 (a)	Amount in Notes Payable to Trust at 12/31/03 (b)	Description of Underlying Debentures of Registrant
				(in millions)			
CPL Capital I	8.00%, Series A	-	$ -	$ -	$ 5	$ 141	TCC, $141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	-	-	-	2	77	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	5.25%, Series B	110,000	3	113	3	113	SWEPCo, $113 million, 5.25% 5-year fixed rate period, Series B
Total		110,000	$ 3	$ 113	$ 10	$ 331	

(a) Amounts are in Other within Other Noncurrent Assets.
(b) Amounts are in Notes Payable to Trust within Long-term Debt.

Each of the business trusts is treated as a nonconsolidated subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under the subordinated debentures, the parent company has also agreed to a security obligation, which represents a full and unconditional guarantee of its capital trust obligation.

Minority Interest in Finance Subsidiary

We formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis) in August 2001. SubOne is a wholly-owned consolidated subsidiary that held the assets of HPL and LIG. Caddis was capitalized with $2 million cash from SubOne for a managing member interest and $750 million from Steelhead Investors LLC (Steelhead) for a noncontrolling preferred member interest. As managing member, SubOne consolidated Caddis. Steelhead was an unconsolidated special purpose entity whose investors had no relationship to us or any of our subsidiaries. The money invested in Caddis by Steelhead was loaned to SubOne.

On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis. As a result, a note payable ($533 million) to Caddis was reported as a component of Long-term Debt on July 1, 2003, the balance of which was $0 and $525 million on December 31, 2004 and December 31, 2003, respectively. Due to the prospective application of FIN 46, we did not change the presentation of Minority Interest in Finance Subsidiary in periods prior to July 1, 2003.

Equity Units

In June 2002, AEP issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consists of a forward purchase contract and a senior note.

The forward purchase contracts obligate the holders to purchase shares of AEP common stock on August 16, 2005. The purchase price per equity unit is $50. The number of shares to be purchased under the forward purchase contract will be determined under a formula based upon the average closing price of AEP common stock near the stock purchase date. Holders may satisfy their obligation to purchase AEP common stock under the forward purchase contracts by allowing the senior notes to be remarketed or by continuing to hold the senior notes and using other resources as consideration for the purchase of stock. If holders remarket their notes, the proceeds from the remarketing will be used to purchase a portfolio of U.S. treasury securities that the holders will pledge to AEP in order to meet their obligations under the forward purchase contracts.

The senior notes have a principal amount of $50 each and mature on August 16, 2007. The senior notes are the collateral that secures the holders' requirement to purchase common stock under the forward purchase contracts.

AEP is making quarterly interest payments on the senior notes at an initial annual rate of 5.75%. The interest rate can be reset through a remarketing, which is initially scheduled for May 2005. AEP makes contract adjustment payments to the purchaser at the annual rate of 3.50% on the forward purchase contracts. The present value of the contract adjustment payments was recorded as a $31 million liability in Equity Unit Senior Notes offset by a charge to Paid-in Capital in June 2002. Interest payments on the senior notes are reported as interest expense. Accretion of the contract adjustment payment liability is reported as interest expense.

AEP applies the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contract are used to repurchase outstanding shares.

Lines of Credit – AEP System

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, 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, 2004, we had credit facilities totaling $2.8 billion to support our commercial paper program. At December 31, 2004, we had $23 million in outstanding commercial paper related to JMG Funding. This commercial paper is specifically associated with the Gavin Scrubber as identified in the "Gavin Scrubber Financing Arrangement" section of Note 16 and is backed by a separate credit facility. This commercial paper does not reduce our available liquidity. As of December 31, 2004, our commercial paper outstanding related to the corporate borrowing program was $0. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $661 million in June 2004 and the weighted average interest rate of commercial paper outstanding during the year was 1.81%. On February 10, 2003, Moody's Investor Services downgraded our short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poor's Rating Services reaffirmed our A-2 short-term rating for commercial paper. On August 2, 2004, Moody's Investor Services placed our ratings on positive outlook.

Outstanding Short-term Debt consisted of:

	December 31, 2004	December 31, 2003
	(in millions)	
Balance Outstanding		
Notes Payable	$ -	$ 18
Commercial Paper – AEP	-	282
Commercial Paper – JMG	23	26
Total	$ 23	$ 326

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. We have no ownership interest in the commercial paper conduits and are not required to consolidate these entities in accordance with GAAP. We continue to service the receivables. We entered into this off-balance sheet transaction to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables, and accelerate its cash collections.

During 2004, AEP Credit renewed its sale of receivables agreement which had expired on August 25, 2004. As a result of the renewal, AEP Credit's sale of receivables agreement will now expire on August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2004, $435 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit is as follows:

	Year Ended December 31, 2004	Year Ended December 31, 2003
	(in millions)	
Proceeds from Sale of Accounts Receivable	$ 5,163	$ 5,221
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	80	124
Deferred Revenue from Servicing Accounts Receivable	1	1
Loss on Sale of Accounts Receivable	7	7
Average Variable Discount Rate	1.50%	1.33%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	78	122
Retained Interest if 20% Adverse Change in Uncollectible Accounts	76	121

Historical loss and delinquency amount for the AEP System's customer accounts receivable managed portfolio is as follows:

	Face Value Year Ended December 31, 2004	Face Value Year Ended December 31, 2003
	(in millions)	
Customer Accounts Receivable Retained	$ 930	$ 1,155
Accrued Unbilled Revenues Retained	592	596
Miscellaneous Accounts Receivable Retained	79	83
Allowance for Uncollectible Accounts Retained	(77)	(124)
Total Net Balance Sheet Accounts Receivable	1,524	1,710
Customer Accounts Receivable Securitized (Affiliate)	435	385
Total Accounts Receivable Managed	$ 1,959	$ 2,095
Net Uncollectible Accounts Written Off	$ 86	$ 39

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $25 million and $30 million at December 31, 2004 and 2003, respectively.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

Our unaudited quarterly financial information is as follows:

(In Millions – Except Per Share Amounts)	2004 Quarterly Periods Ended March 31	June 30	September 30	December 31
Revenues	$ 3,364	$ 3,408	$ 3,780	$ 3,505
Operating Income	633	413	639	306
Income Before Discontinued Operations and Extraordinary Item	289	151	412	275
Net Income	282	100	530	177
Earnings per Share Before Discontinued Operations and Extraordinary Item (a)	0.73	0.38	1.04	0.69
Earnings per Share	0.71	0.25	1.34	0.45

(In Millions – Except Per Share Amounts)	2003 Quarterly Periods Ended March 31	June 30	September 30	December 31
Revenues	$ 3,806	$ 3,491	$ 3,966	$ 3,404
Operating Income (Loss)	651	434	760	(91)
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes	293	177	307	(255)
Net Income (Loss)	440	175	257	(762)
Earnings (Loss) per Share Before Discontinued Operations and Cumulative Effect of Accounting Changes (b)	0.82	0.45	0.78	(0.65)
Earnings (Loss) per Share (c)	1.24	0.44	0.65	(1.93)

(a) Amounts for 2004 do not add to $2.85 earnings per share before Discontinued Operations and Extraordinary Item due to rounding.
(b) Amounts for 2003 do not add to $1.35 earnings per share before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes due to rounding and the dilutive effect of shares issued in 2003.
(c) Amounts for 2003 do not add to $0.29 earnings per share due to rounding and the dilutive effect of shares issued in 2003.

Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes for the fourth quarter of 2003 ($255 million loss) was significantly lower than the previous three quarters due to asset impairments, investment value losses and other related charges. These pretax writedowns ($650 million in the fourth quarter of 2003) were made to reflect impairments and discontinued operations as discussed in Note 10.

19. SUBSEQUENT EVENT

On January 27, 2005, we sold a 98% controlling interest in HPL, 30 BCF of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. We are retaining a 2% ownership interest in HPL and will provide certain transitional administrative services to the buyer. The determination of the amount of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the Bank of America (BOA) dispute. We provided an indemnity in an amount up to the purchase price to the purchaser for damages, if any, arising from litigation with BOA (see "Enron Bankruptcy – Right to use of cushion gas agreements" section of Note 7).

We also have a put option expiring in 2006, which allows us to sell our remaining 2% interest to the buyer for approximately $16 million.

HPL is classified as held and used instead of held for sale as of December 31, 2004 due to the magnitude and uncertainty surrounding the BOA dispute and what level of indemnification a potential buyer might require. In addition, the indicative bid and our Board of Director's approval to sell HPL were received subsequent to December 31, 2004.

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