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

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2004

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

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
0-18135	AEP GENERATING COMPANY (An Ohio Corporation)	31-1033833
0-346	AEP TEXAS CENTRAL COMPANY (A Texas Corporation)	74-0550600
0-340	AEP TEXAS NORTH COMPANY (A Texas Corporation)	75-0646790
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation)	61-0247775
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 716-1000	

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒. No. ☐

Indicate by check mark if disclosure of delinquent filers with respect to American Electric Power Company, Inc. pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark if disclosure of delinquent filers with respect to Appalachian Power Company, Indiana Michigan Power Company or Ohio Power Company pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements of Appalachian Power Company or Ohio Power Company incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether American Electric Power Company, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☒ No ☐

Indicate by check mark whether AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are accelerated filers (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☒

AEP Generating Company, AEP Texas North Company, Columbus Southern Power Company, Kentucky Power Company and Public Service Company of Oklahoma meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

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

Registrant	Title of each class	Name of each exchange on which registered
AEP Generating Company	None	
AEP Texas Central Company	None	
AEP Texas North Company	None	
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
	9.25% Equity Units	New York Stock Exchange
Appalachian Power Company	None	
Columbus Southern Power Company	None	
Indiana Michigan Power Company	6% Senior Notes, Series D, Due 2032	New York Stock Exchange
Kentucky Power Company	None	
Ohio Power Company	None	
Public Service Company of Oklahoma	6% Senior Notes, Series B, Due 2032	New York Stock Exchange
Southwestern Electric Power Company	None	

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

Registrant	Title of each class
AEP Generating Company	None
AEP Texas Central Company	4.00% Cumulative Preferred Stock, Non-Voting, $100 par value
	4.20% Cumulative Preferred Stock, Non-Voting, $100 par value
AEP Texas North Company	None
American Electric Power Company, Inc.	None
Appalachian Power Company	4.50% Cumulative Preferred Stock, Voting, no par value
Columbus Southern Power Company	None
Indiana Michigan Power Company	4.125% Cumulative Preferred Stock, Non-Voting, $100 par value
Kentucky Power Company	None
Ohio Power Company	4.50% Cumulative Preferred Stock, Voting, $100 par value
Public Service Company of Oklahoma	None
Southwestern Electric Power Company	4.28% Cumulative Preferred Stock, Non-Voting, $100 par value
	4.65% Cumulative Preferred Stock, Non-Voting, $100 par value
	5.00% Cumulative Preferred Stock, Non-Voting, $100 par value

	Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants at December 31, 2004	Number of shares of common stock outstanding of the registrants at December 31, 2004
AEP Generating Company	None	1,000 ($1,000 par value)
AEP Texas Central Company	None	2,211,678 ($25 par value)
AEP Texas North Company	None	5,488,560 ($25 par value)
American Electric Power Company, Inc.	$13,593,768,974	395,858,153 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Columbus Southern Power Company	None	16,410,426 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Kentucky Power Company	None	1,009,000 ($50 par value)
Ohio Power Company	None	27,952,473 (no par value)
Public Service Company of Oklahoma	None	9,013,000 ($15 par value)
Southwestern Electric Power Company	None	7,536,640 ($18 par value)

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

American Electric Power Company, Inc. owns, directly or indirectly, all of the common stock of AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (see Item 12 herein).

Documents Incorporated By Reference

Description	Part of Form 10-K Into Which Document Is Incorporated
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2004:	Part II
AEP Generating Company	
AEP Texas Central Company	
AEP Texas North Company	
American Electric Power Company, Inc.	
Appalachian Power Company	
Columbus Southern Power Company	
Indiana Michigan Power Company	
Kentucky Power Company	
Ohio Power Company	
Public Service Company of Oklahoma	
Southwestern Electric Power Company	
Portions of Proxy Statement of American Electric Power Company, Inc. for 2005 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2004	Part III
Portions of Information Statements of the following companies for 2005 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2004:	Part III
Appalachian Power Company	
Ohio Power Company	

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

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

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GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP
AEP	American Electric Power Company, Inc.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP
AEP Power Pool	APCo, CSPCo, I&M, KPCo and OPCo, as parties to the Interconnection Agreement
AEPR	AEP Resources, Inc., a subsidiary of AEP
AEPSC or Service Corporation	American Electric Power Service Corporation, a service subsidiary of AEP
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries
AEP Utilities	AEP Utilities, Inc., subsidiary of AEP, formerly, Central and South West Corporation
AFUDC	Allowance for funds used during construction (the net cost of borrowed funds, and a reasonable rate of return on other funds, used for construction under regulatory accounting)
ALJ	Administrative law judge
APCo	Appalachian Power Company, an electric utility subsidiary of AEP
Btu	British thermal unit
Buckeye	Buckeye Power, Inc., an unaffiliated corporation
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
Cardinal Station	Generating facility co-owned by Buckeye and OPCo
Centrica	Centrica U.S. Holdings, Inc., and its affiliates collectively, unaffiliated companies
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CG&E	The Cincinnati Gas & Electric Company, an unaffiliated utility company
Cook Plant	The Donald C. Cook Nuclear Plant (2,143 MW), owned by I&M, and located near Bridgman, Michigan
CSPCo	Columbus Southern Power Company, a public utility subsidiary of AEP
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation
DOE	United States Department of Energy
DP&L	The Dayton Power and Light Company, an unaffiliated utility company
Dow	The Dow Chemical Company, and its affiliates collectively, unaffiliated companies
East zone public utility subsidiaries	APCo, CSPCo, I&M, KPCo and OPCo
ECOM	Excess cost over market
EMF	Electric and Magnetic Fields
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
FPA	Federal Power Act
FUCO	Foreign utility company as defined under PUHCA
I&M	Indiana Michigan Power Company, a public utility subsidiary of AEP
I&M Power Agreement	Unit Power Agreement Between AEGCo and I&M, dated March 31, 1982
Interconnection Agreement	Agreement, dated July 6, 1951, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants
IURC	Indiana Utility Regulatory Commission
KPCo	Kentucky Power Company, a public utility subsidiary of AEP
KPSC	Kentucky Public Service Commission
LLWPA	Low-Level Waste Policy Act of 1980
LPSC	Louisiana Public Service Commission
MECPL	Mutual Energy CPL, L.P., a Texas REP and former AEP affiliate
MEWTU	Mutual Energy WTU, L.P., a Texas REP and former AEP affiliate

Abbreviation or Acronym	Definition
MISO	Midwest Independent Transmission System Operator
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NOx	Nitrogen oxide
NPC	National Power Cooperatives, Inc., an unaffiliated corporation
NRC	Nuclear Regulatory Commission
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff, filed with FERC
OCC	Corporation Commission of the State of Oklahoma
Ohio Act	Ohio electric restructuring legislation
OPCo	Ohio Power Company, a public utility subsidiary of AEP
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo together own a 44.2% equity interest
PJM	PJM Interconnection, L.L.C.; a regional transmission organization
Pro Serv	AEP Pro Serv, Inc., a subsidiary of AEP
PSO	Public Service Company of Oklahoma, a public utility subsidiary of AEP
PTB	Price to beat, as defined by the Texas Act
PUCO	The Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 1935, as amended
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REP	Retail electricity provider
Rockport Plant	A generating plant owned and partly leased by AEGCo and I&M (1,300 MW, coal-fired) located near Rockport, Indiana
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
S&P	Standard & Poor's Ratings Service
SO_2	Sulfur dioxide
SO_2 Allowance	An allowance to emit one ton of sulfur dioxide granted under the Clean Air Act Amendments of 1990
SPP	Southwest Power Pool
S&P	Standard & Poor's Ratings Service
STP	South Texas Project Nuclear Generating Plant, of which TCC owns 25.2%
STPNOC	STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners, including TCC
SWEPCo	Southwestern Electric Power Company, a public utility subsidiary of AEP
TCA	Transmission Coordination Agreement dated January 1, 1997 by and among, PSO, SWEPCo, TCC, TNC and AEPSC, which allocates costs and benefits in connection with the operation of the transmission assets of the four public utility subsidiaries
TCC	AEP Texas Central Company, formerly Central Power and Light Company, a public utility subsidiary of AEP
TEA	Transmission Equalization Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets
Texas Act	Texas electric restructuring legislation
TNC	AEP Texas North Company, formerly West Texas Utilities Company, a public utility subsidiary of AEP
Tractebel	Tractebel Energy Marketing, Inc.
TVA	Tennessee Valley Authority
Virginia Act	Virginia electric restructuring legislation
VSCC	Virginia State Corporation Commission
WVPSC	West Virginia Public Service Commission
West zone public utility subsidiaries	PSO, SWEPCo, TCC and TNC

FORWARD-LOOKING INFORMATION

This report made by AEP and certain of 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.

PART I

ITEM 1. BUSINESS

GENERAL

OVERVIEW AND DESCRIPTION OF SUBSIDIARIES

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

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

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

At December 31, 2004, the subsidiaries of AEP had a total of 19,893 employees. Because it is a holding company rather than an operating company, AEP has no employees. The public utility subsidiaries of AEP are:

APCo (organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 934,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2004, APCo and its wholly owned subsidiaries had 2,375 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo integrated into PJM on October 1, 2004.

CSPCo (organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 707,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. At December 31, 2004, CSPCo had 1,150 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. Among the principal industries served are food processing, chemicals, primary metals, electronic machinery and paper products. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo integrated into PJM on October 1, 2004.

I&M (organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 579,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2004, I&M had 2,634 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and miscellaneous plastic products and chemicals and allied products. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M integrated into PJM on October 1, 2004.

KPCo (organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 175,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2004, KPCo had 424 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo integrated into PJM on October 1, 2004.

Kingsport Power Company (organized in Virginia in 1917) provides electric service to approximately 46,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee. Kingsport Power Company does not own any generating facilities and integrated into PJM on October 1, 2004. It purchases electric power from APCo for distribution to its customers. At December 31, 2004, Kingsport Power Company had 58 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 707,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2004, OPCo had 2,177 employees. Among the principal industries served by OPCo are primary metals, rubber and plastic products, stone, clay, glass and concrete products, petroleum refining and chemicals. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo integrated into PJM on October 1, 2004.

PSO (organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 509,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2004, PSO had 1,197 employees. Among the principal industries served by PSO are natural gas and oil production, oil refining, steel processing, aircraft maintenance, paper manufacturing and timber products, glass, chemicals, cement, plastics, aerospace manufacturing, telecommunications, and rubber goods. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

SWEPCo (organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 444,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2004, SWEPCo had 1,378 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing, and metal refining. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

TCC (organized in Texas in 1945) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 713,000 retail customers through REPs in southern Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, a municipality, rural electric cooperatives and other market participants. At December 31, 2004, TCC had 933 employees. Among the principal industries served by TCC are oil and gas extraction, food processing, apparel, metal refining, chemical and petroleum refining, plastics, and machinery equipment. In addition to its AEP System interconnections, TCC is a member of ERCOT.

TNC (organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 188,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2004, TNC had 415 employees. Among the principal industries served by TNC are agriculture and the manufacturing or processing of cotton seed products, oil products, precision and consumer metal products, meat products and gypsum products. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

Wheeling Power Company (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 41,000 retail customers in northern West Virginia. Wheeling Power Company does not own any generating facilities and integrated into PJM on October 1, 2004. It purchases electric power from OPCo for distribution to its customers. At December 31, 2004, Wheeling Power Company had 61 employees.

AEGCo (organized in Ohio in 1982) is an electric generating company. AEGCo sells power at wholesale to I&M and KPCo. AEGCo has no employees.

SERVICE COMPANY SUBSIDIARY

AEP also owns a service company subsidiary, AEPSC. AEPSC provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP System companies. The executive officers of AEP and its public utility subsidiaries are all employees of AEPSC. At December 31, 2004, AEPSC had 6,208 employees.

RISK FACTORS

General Risks Of Our Regulated Operations

Rate regulation may delay or deny full recovery of costs. *(Applies to each registrant.)*

Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of the applicable utility's expenses incurred in a test year. Thus, the rates a utility is allowed to charge may or may not match its expenses at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs.

The rates that certain of our utilities may charge their customers may be reduced. *(Applies to AEP and PSO, SWEPCo and TCC, respectively.)*

In February 2003, the OCC required 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's requirements indicating that its annual revenues were $41 million less than costs. The OCC Staff and intervenors filed testimony regarding their recommendations of a decrease in annual existing rates between $15 and $36 million. In addition, one party recommended that $30 million of PSO's natural gas costs not be recovered from customers because it failed to implement a procurement strategy that this party alleged would have resulted in lower natural gas costs. PSO filed rebuttal testimony in February 2005, which indicated a decrease of PSO's revenue deficiency from $41 million to $28 million, although much of that decrease includes 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 PSO's revenues, results of operations, cash flows and financial condition.

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 Central and South West Corporation ("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. 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 SWEPCo's future results of operations and cash flows.

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. 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. In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCC's requested $67 million rate increase. The recommendations ranged from a decrease in existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. The ALJs issued recommendations in November 2004 which would reduce TCC's existing rates by $51 million to $78 million from existing levels. The PUCT will hold additional hearings on two major issues in March 2005. The PUCT is expected to issue a decision in the first half of 2005. If the PUCT orders a rate reduction, it could adversely impact TCC's future results of operations and cash flows.

The amount that PSO seeks to recover for fuel costs is currently being reviewed. *(Applies to PSO.)*

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP's West zone public utility subsidiaries of purchased power costs for periods prior to January 1, 2002. 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, the OCC Staff and the Attorney General of Oklahoma have made filings indicating that recovery should be disallowed altogether or reduced in the range of $18 million to $9 million. These filings raised certain issues of an allocation approved under FERC. 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. The OCC conducted a hearing on the jurisdictional matter in January 2005 but has not issued a decision. If the OCC determines, as a result of the review that a portion of PSO's fuel and purchased power costs should not be recovered, there could be an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

The base rates that certain of our utilities charge are currently capped or frozen. *(Applies to AEP, CSPCo, I&M, OPCo and SWEPCo.)*

Base rates charged to customers in Indiana, Michigan, Louisiana and Ohio are currently either frozen or capped. To the extent our costs in these states exceed the applicable cap or frozen rate, those costs are not recoverable from customers.

Certain of our revenues and results of operations are subject to risks that are beyond our control. *(Applies to each registrant.)*

Unless mitigated by timely and adequate regulatory recovery, the cost of repairing damage to our utility facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events, in excess of reserves established for such repairs, may adversely impact our revenues, operating and capital expenses and results of operations.

We are exposed to nuclear generation risk. *(Applies to AEP, I&M and TCC.)*

Through I&M and TCC, we have interests in four nuclear generating units, which interests equal 2,740 MW, or 7% of our generation capacity. (TCC has entered an agreement to sell its interest in two nuclear generating units.) We are, therefore, also subject to the risks of nuclear generation, which include the following:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- uncertainties with respect to contingencies and assessment amounts if insurance coverage is inadequate; and,
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

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

The different regional power markets in which we compete or will compete in the future have changing transmission regulatory structures, which could affect our performance in these regions. *(Applies to each registrant.)*

Our results are likely to be affected by differences in the market and transmission regulatory structures in various regional power markets. Problems or delays that may arise in the formation and operation of new regional transmission organizations, or "RTOs", may restrict our ability to sell power produced by our generating capacity to certain markets if there is insufficient transmission capacity otherwise available. The rules governing the various regional power markets may also change from time to time which could affect our costs or revenues. Because it remains unclear which companies will be participating in the various regional power markets, or how RTOs will develop or what regions they will cover, we are unable to assess fully the impact that these power markets may have on our business.

AEP's East zone public utility subsidiaries joined PJM on October 1, 2004. Two of AEP's west zone public utility subsidiaries are members of SPP. In February 2004, FERC granted RTO status to the SPP, subject to fulfilling specified requirements. In October 2004, the FERC issued an order granting final RTO status to SPP subject to certain filings.

The Louisiana and Arkansas Commissions are concerned about the effect on retail ratepayers of utilities in Louisiana and Arkansas joining RTOs. The Commissions have ordered the utilities in those states, including us, to analyze and submit to the Commissions the costs and benefits of RTO options available to the utilities. The Louisiana Commission has also determined that certain RTO structures that contemplate legally transferring transmission assets to it are presumptively not in the public interest.

To the extent we are faced with conflicting state and Federal requirements as to our participation in RTOs, it could adversely affect our ability to operate and recover transmission costs from retail customers. Management is unable to predict the outcome of these transmission regulatory actions and proceedings or their impact on the timing and operation of RTOs, our transmission operations or future results of operations and cash flows.

The FERC may reduce the amount we may charge third parties for using our transmission facilities. *(Applies to AEP and AEP's East zone public utility subsidiaries.)*

In July 2003, the FERC issued an order directing PJM and the 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 Midwest ISO and PJM expanded 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 under the RTOs' revenue distribution protocols.

AEP and several other utilities in the Combined Footprint filed a proposal for new rates to become effective December 1, 2004. In November 2004, FERC eliminated the T&O rates and replaced the rates temporarily through March 2006 with seams elimination cost adjustment (SECA) fees. AEP's East zone public utility subsidiaries received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the last twelve months prior to joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA fees was $171 million. Effective April 2006, all transmission costs that would otherwise have been defrayed by T&O rates in the Combined Footprint will be subject to recovery from native load customers of AEP's East zone public utility subsidiaries. At this time, management is unable to predict whether any resultant increase in rates applicable to AEP's internal load will be recoverable on a timely basis from state retail customers. Unless new replacement rates compensate AEP for its lost revenues, and unless any increase in AEP's East zone public utility subsidiaries' transmission expenses from these new rates are fully recovered in retail rates on a timely basis, future results of operations, cash flows and financial condition will be adversely affected.

We are subject to regulation under the Public Utility Holding Company Act of 1935. *(Applies to each registrant.)*

Our system is subject to the jurisdiction of the SEC under PUHCA. The rules and regulations under PUHCA impose a number of restrictions on the operations of registered holding company systems. These restrictions include a requirement that the SEC approve in advance securities issuances, sales and acquisitions of utility assets, sales and acquisitions of securities of utility companies and acquisitions of other businesses. PUHCA also generally limits the operations of a registered holding company to a single integrated public utility system, plus additional energy-related businesses. PUHCA rules limit the dividends that our subsidiaries may pay from unearned surplus.

Our merger with CSW may ultimately be found to violate PUHCA. *(Applies to AEP, PSO, SWEPCo, TCC and TNC.)*

We acquired CSW in a merger completed on June 15, 2000. Among the more significant assets we acquired as a result of the merger were four additional domestic electric utility companies – PSO, SWEPCo, TCC and TNC. On January 18, 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC's June 14, 2000 order approving the merger failed to properly find that the merger meets the requirements of PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCA's requirement that the electric utilities be "physically interconnected" and confined to a "single area or region." In August 2004, the SEC announced it would conduct hearings on this issue. A hearing was held January 10, 2005 before an ALJ. An initial decision is expected from the ALJ later this year. The SEC will have the opportunity to review the initial decision.

We believe that the merger meets the requirements of PUHCA and expect the matter to be resolved favorably. We can give no assurance, however, that: (i) the SEC or any applicable court review will find that the merger complies with PUHCA, or (ii) the SEC or any applicable court review will not impose material adverse conditions on us in order to find that the merger complies with PUHCA. If the merger were ultimately found to violate PUHCA, we could be required to take remedial actions or divest assets, which could harm our results of operations or financial condition.

We operate in a non-uniform and fluid regulatory environment. *(Applies to each registrant.)*

In most instances and in varying degrees, the rates charged by the domestic utility subsidiaries are approved by the FERC and the eleven state utility commissions. FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail generation and distribution rates. Several of the eleven state retail jurisdictions in which our domestic electric utilities operate have enacted restructuring legislation. Restructuring legislation in Texas requires the legal separation of generation and related assets from the transmission and distribution assets of the electric utilities in that state. In Ohio, we are complying with restructuring legislation through the continued functional separation of the operations of our Ohio utility subsidiaries. As a result of restructuring legislation in Texas and Ohio, a significant portion of our domestic generation is no longer directly regulated by state utility commissions as to rates. TCC has sold some of its generation in Texas and is in the process of selling its remaining generation. Our utility operations in the remaining state retail jurisdictions that have not enacted any restructuring legislation currently plan to adhere to the vertically-integrated utility model with cost recovery through regulated rates.

Our business plan is based on the regulatory framework as described. There can be no assurance that the states that have pursued restructuring will not reverse such policies; nor can there be assurance that the states that have not enacted restructuring legislation will not do so in the future. In addition to the multiple levels of regulation at the state level in which we operate, our business is subject to extensive federal regulation. There can be no assurance that the federal legislative and regulatory initiatives (which have occurred over the past few years and which have generally facilitated competition in the energy sector) will continue or will not be reversed.

Further alteration of the regulatory landscape in which we operate will impact the effectiveness of our business plan and may, because of the continued uncertainty, harm our financial condition and results of operations.

Risks Related to Market, Economic or International Financial Volatility

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses. *(Applies to each registrant other than AEGCo.)*

Following the bankruptcy of Enron, the credit ratings agencies initiated a thorough review of the capital structure and the quality and stability of earnings of energy companies, including us. The agencies made ratings changes at that time. Further negative ratings actions could constrain the capital available to our industry and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed and future results of operations could be adversely affected.

Moody's has assigned an investment grade credit rating to the senior unsecured long-term debt of each registrant other than AEGCo (collectively, the "Rated Issuers"). Moody's has further assigned an outlook of stable for each of the Rated Issuers other than AEP, which Moody's assigned an outlook of positive in 2004. S&P has also assigned an investment grade credit rating to the senior unsecured long-term debt of each of the Rated Issuers. S&P has assigned an outlook of stable for each of the Rated Issuers. Fitch has also assigned an investment grade credit rating (with stable outlook) to the senior unsecured long-term debt of each of the Rated Issuers. Apart from Moody's improving the outlook on AEP noted above, none of these ratings was adjusted by any rating agency during 2004.

Moody's has assigned AEP a short-term debt rating of P-3. S&P has assigned AEP a short-term debt rating of A-2. Fitch has assigned AEP a short-term debt rating of F-2. As a result of the split rating, AEP's access to the commercial paper market may be limited and the short-term borrowing costs of each registrant may increase (because AEP's subsidiaries conduct short-term borrowing through AEP and on the same terms available to AEP).

If Moody's or S&P were to downgrade the long-term rating of any of the Rated Issuers, particularly below investment grade, the borrowing costs of that Rated Issuer would increase, which would diminish its financial results. In addition, it would likely be required to pay a higher interest rate in future financings, and its potential pool of investors and funding sources could decrease.

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

The underfunded condition of our retirement plans may require additional significant contributions. *(Applies to each registrant.)*

AEP provides defined benefit pension plans ("Pension Plans") for the employees of our subsidiaries. In addition, AEP provides health care and life insurance benefit plans for retired employees.

Low prevailing interest rates have increased the pension plans' liability. The combined Pension Plans' liabilities based on service and pay to date ("Accumulated Benefit Obligation") exceeded the value of the assets at December 31, 2004. As of December 31, 2004, the fair value of the Pension Plans assets was $3.56 billion while the Accumulated Benefit Obligation was estimated at $4.0 billion, an underfunding of approximately $450 million. For the individual pension plans that were underfunded based on the Accumulated Benefit Obligation, underfunding totaled approximately $474 million. In order to fund the qualified pension plans fully by the end of 2005, a discretionary contribution of $200 million was made in the fourth quarter of 2004 and discretionary contributions of $100 million per quarter are expected in 2005.

AEP also made contributions of $137 million to postretirement health care and life insurance benefits trust funds in 2004, and expects to contribute significant amounts in the future.

We cannot predict the future performance of the investment markets. A downturn in the investment markets could have a material negative impact on the net asset value of the plans' trust accounts and increase the underfunding of the Pension Plans, net of benefit obligations. This may necessitate significant cash contributions to the Pension Plans. Changes in interest rates may also materially affect the pension and postretirement health care and life insurance benefit liabilities and the cash contributions needed to fund those liabilities. Changes in the laws and regulations governing the plans may increase or decrease the required contributions.

Our operating results may fluctuate on a seasonal and quarterly basis. *(Applies to each registrant.)*

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the terms of power sale contracts that we enter into. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. We expect that unusually mild weather in the future could diminish our results of operations and harm our financial condition.

Changes in technology may significantly affect our business by making our power plants less competitive. *(Applies to each registrant.)*

A key element of our business model is that generating power at central power plants achieves economies of scale and produces power at relatively low cost. There are other technologies that produce power, most notably fuel cells, microturbines, windmills and photovoltaic (solar) cells. It is possible that advances in technology will reduce the cost of alternative methods of producing power to a level that is competitive with that of most central power station electric production. If this were to happen and if these technologies achieved economies of scale, our market share could be eroded, and the value of our power plants could be reduced. Changes in technology could also alter the channels through which retail electric customers buy power, thereby harming our financial results.

Changes in commodity prices may increase our cost of producing power or decrease the amount we receive from selling power, harming our financial performance. *(Applies to each registrant.)*

We are heavily exposed to changes in the price and availability of coal because most of our generating capacity is coal-fired. We have contracts of varying durations for the supply of coal for most of our existing generation capacity, but as these contracts end or otherwise not honored, we may not be able to purchase coal on terms as favorable as the current contracts.

We also own natural gas-fired facilities, which increases our exposure to the more volatile market prices of natural gas.

Changes in the cost of coal or natural gas and changes in the relationship between such costs and the market prices of power will affect our financial results. Since the prices we obtain for power may not change at the same rate as the change in coal or natural gas costs, we may be unable to pass on the changes in costs to our customers. In addition, the prices we can charge our retail customers in some jurisdictions are capped and our fuel recovery mechanisms in other states are frozen for various periods of time.

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

At times, demand for power could exceed our supply capacity. *(Applies to each registrant other than TCC and TNC.)*

We are currently obligated to supply power in parts of eleven states. From time to time, because of unforeseen circumstances, the demand for power required to meet these obligations could exceed our available generation capacity. If this occurs, we would have to buy power on the market. We may not always have the ability to pass these costs on to our customers because some of the states we operate in do not allow us to increase our rates in response to increased fuel cost charges. Since these situations most often occur during periods of peak demand, it is possible that the market price for power at that time would be very high. Even if a supply shortage was brief, we could suffer substantial losses that could diminish our results of operations.

Risks Relating To State Restructuring

We have limited ability to pass on our costs of production to our customers. *(Applies to each registrant.)*

We are exposed to risk from changes in the market prices of coal and natural gas used to generate power where generation is no longer regulated or where existing fuel clauses are suspended or frozen. Recently, the price of coal and natural gas has increased materially. The protection afforded by retail fuel clause recovery mechanisms has been eliminated by the implementation of customer choice in Ohio and in the ERCOT area of Texas. There may be similar risks should customer choice be similarly implemented in other states. Because the risk of generating costs cannot be passed through to customers as a matter of right in Ohio and the ERCOT area of Texas, we retain these risks.

A fuel clause in West Virginia has been suspended per a settlement reached in a state restructuring proceeding. However, as restructuring has not been implemented in West Virginia, the fuel clause may be reactivated. An extension of the currently pending fuel clause in Indiana is being negotiated.

Our default service obligations in Ohio do not restrict customers from switching suppliers of power. *(Applies to AEP, CSPCo and OPCo.)*

Those default service customers that we serve in Ohio may choose to purchase power from alternative suppliers. Should they choose to switch from us, our sales of power may decrease. Customers originally choosing alternative suppliers may switch to our default service obligations. This may increase demand above our facilities' available capacity. Thus, any such switching by customers could have an adverse effect on our results of operations and financial position. Conversely, to the extent the power sold to meet the default service obligations could have been sold to third parties at more favorable wholesale prices, we will have incurred potentially significant lost opportunity costs.

If CSPCo and OPCo are unable to remain functionally separated, they will need SEC approval to legally separate their assets. *(Applies to CSPCo and OPCo.)*

Ohio has enacted restructuring legislation in the Ohio Act. CSPCo and OPCo each currently comply with the Ohio Act as a functionally separated electric utility. The PUCO has approved the rate stabilization plan that does not contemplate legal separation at least through 2008. However, we can give no assurance that we can remain functionally separated following that. If CSPCo and OPCo are unable to remain functionally separated and we are required to legally separate, they would need SEC approval to legally separate.

Some laws and regulations governing restructuring of the wholesale generation market in Michigan and Virginia have not yet been interpreted or adopted and could harm our business, operating results and financial condition. *(Applies to AEP and APCo and I&M, respectively.)*

While the electric restructuring laws in Michigan and Virginia established the general framework governing the retail electric market, the laws required the utility commission in each state to issue rules and determinations implementing the laws. Some of the regulations governing the retail electric market have not yet been adopted by the utility commission in each state. These laws, when they are interpreted and when the regulations are developed and adopted, may harm our business, results of operations and financial condition. Virginia restructuring legislation was enacted in 1999 providing for retail choice of generation suppliers to be phased in over two years beginning January 1, 2002. It required jurisdictional utilities to unbundle their power supply and energy delivery rates and to file functional separation plans by January 1, 2002. APCo filed its plan with VSCC and, following VSCC approval of a settlement agreement, now operates in Virginia as a functionally separated electric utility charging unbundled rates for its retail sales of electricity. The settlement agreement addressed functional separation, leaving decisions related to legal separation for later VSCC consideration. Legislation in Virginia has been adopted which extends a cap on electricity rates until 2010.

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Rates for retail electric service for I&M's Michigan customers were unbundled (though they continue to be regulated) to allow customers the ability to evaluate the cost of generation service for comparison with other suppliers. At December 31, 2004, none of I&M's Michigan customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

There is uncertainty as to our recovery of deferred fuel balances and stranded costs resulting from industry restructuring in Texas. *(Applies to AEP and TCC.)*

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 the true-up proceeding described below. This reconciliation covers the period from July 1998 through December 2001. The PUCT will review an ALJ report addressing the reconciliation and will likely issue a decision in the first quarter of 2005. The over-recovery balance and the subsequent provisions for probable disallowances totaled $212 million, including interest, at December 31, 2004. The PUCT will net the final amount against recoverable amounts determined by the true-up proceeding.

Restructuring legislation in Texas required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. We have elected to use the sale of assets method to determine the market value of all of the generation assets of TCC for stranded cost purposes. The amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. TCC's sale of its generating assets will be subject to a review in a true-up proceeding conducted by the PUCT. TCC's recorded net regulatory asset for amounts subject to approval in the true-up proceeding, net of the deferred fuel over-recovery described above, is approximately $1.6 billion. We estimate that TCC's true-up filing will exceed the total of its recorded net regulatory asset. Management expects that the true-up proceeding will be contentious and could possibly result in disallowances. If we are unable, after the true-up proceeding, to recover all or a portion of our stranded plant costs, generation-related net regulatory assets, wholesale capacity auction true-up regulatory assets, other restructuring true-up items and costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Collection of our revenues in Texas is concentrated in a limited number of REPs. *(Applies to AEP, TCC and TNC.)*

Our revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity we distribute to their customers. Currently, we do business with approximately forty three REPs. Adverse economic conditions, structural problems in the new Texas market or financial difficulties of one or more REPs could impair the ability of these REPs to pay for our services or could cause them to delay such payments. We depend on these REPs for timely remittance of payments. Any delay or default in payment could adversely affect the timing and receipt of our cash flows thereby have an adverse effect on our liquidity.

We may not be able to respond effectively to competition. *(Applies to each registrant.)*

We may not be able to respond in a timely or effective manner to the many changes in the power industry that may occur as a result of regulatory initiatives to increase competition. These regulatory initiatives may include deregulation of the electric utility industry in some markets. To the extent that competition increases, our profit margins may be negatively affected. Industry deregulation may not only continue to facilitate the current trend toward consolidation in the utility industry but may also encourage the disaggregation of other vertically integrated utilities into separate generation, transmission and distribution businesses. As a result, additional competitors in our industry may be created, and we may not be able to maintain our revenues and earnings levels or pursue our growth strategy.

While demand for power is generally increasing throughout the United States, the rate of construction and development of new, more efficient electric generation facilities may exceed increases in demand in some regional electric markets. The start-up of new facilities in the regional markets in which we have facilities could increase competition in the wholesale power market in those regions, which could harm our business, results of operations and financial condition. Also, industry restructuring in regions in which we have substantial operations could affect our operations in a manner that is difficult to predict, since the effects will depend on the form and timing of the restructuring.

Risks Related to Environmental Regulation

Our costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws could harm our cash flow and profitability. *(Applies to each registrant other than TCC and TNC.)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past and we expect that they will increase in the future. Costs of compliance with environmental regulations could harm our industry, our business and our results of operations and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. Additionally, in July 2004 attorneys general of eight states and others sued AEP and other utilities alleging that carbon dioxide emissions from power generating facilities constitute a public nuisance under federal common law. The suits seek injunctive relief in the form of specific emission reduction commitments from the defendants. While we believe the claims are without merit, the costs associated with reducing carbon dioxide emissions could harm our business and our results of operations and financial position.

We anticipate that we will incur considerable capital costs for compliance. *(Applies to each registrant other than TCC and TNC.)*

Most of our generating capacity is coal burning. We plan to install new emissions control equipment and may be required to upgrade existing equipment, purchase emissions allowances or reduce operations. We estimate that we will invest approximately $600 million to comply with existing federal and state regulations designed to limit nitrogen oxide ("NOx") emissions and approximately $1.2 billion to comply with existing federal and state regulations designed to limit sulfur dioxide ("SO_2") emissions. We estimate that we will invest approximately $1.8 billion (and an additional $150 million in operation and maintenance expenses) to comply with currently proposed, but as yet unadopted, federal regulations designed to limit NOx, SO_2 and mercury emissions through 2010, assuming certain contingencies. Between 2011 and 2020 we expect to incur additional costs for pollution control technology retrofits and investment of $1.6 billion. However, post-2010 capital investment estimates are quite uncertain. 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. The actual costs to comply could differ significantly from the estimates. All of the costs are incremental to our current investment base and operating cost structure. These expenditures for pollution control technologies, replacement generation and associated operating costs should be recoverable from customers through regulated rates (in regulated jurisdictions) and should be recoverable through market prices (in deregulated jurisdictions). If not, those costs could adversely affect future results of operations and cash flows, and possibly financial condition.

Governmental authorities may assess penalties on us for failures to comply with environmental laws and regulations. *(Applies to each registrant.)*

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines against us. Recent lawsuits by the EPA and various states filed against us highlight the environmental risks faced by generating facilities, in general, and coal-fired generating facilities, in particular.

Since 1999, we have been involved in litigation regarding generating plant emissions under the Clean Air Act. Federal EPA and a number of states alleged that we and eleven unaffiliated utilities modified certain units at coal-fired generating plants in violation of the Clean Air Act. Federal EPA filed complaints against certain AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20-year period.

If these actions are resolved against us, substantial modifications of our existing coal-fired power plants would be required. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay penalties and/or halt operations. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Other parties have settled similar lawsuits. An unaffiliated utility which operates certain plants jointly owned by CSPCo reached a tentative agreement to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing and a settlement could impact the operation of certain of the jointly owned plants. 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.

Risks Related to Power Trading and Wholesale Businesses

Our revenues and results of operations are subject to market risks that are beyond our control. *(Applies to each registrant.)*

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

Volatility in market prices for fuel and power may result from:

- weather conditions;
- seasonality;
- power usage;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- demand for energy commodities;
- natural gas, crude oil and refined products, and coal production levels;
- natural disasters, wars, embargoes and other catastrophic events; and
- federal, state and foreign energy and environmental regulation and legislation.

Our power trading (including coal, gas and emission allowances trading and power marketing) and risk management policies cannot eliminate the risk associated with these activities. *(Applies to each registrant.)*

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

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

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

Our financial performance may be adversely affected if we are unable to operate our pooled electric generating facilities successfully. *(Applies to each registrant.)*

Our performance is highly dependent on the successful operation of our electric generating facilities. Operating electric generating facilities involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- fuel supply interruptions; and
- catastrophic events such as fires, earthquakes, explosions, terrorism, floods or other similar occurrences.

A decrease or elimination of revenues from power produced by our electric generating facilities or an increase in the cost of operating the facilities would adversely affect our results of operations.

Parties with whom we have contracts may fail to perform their obligations, which could harm our results of operations. *(Applies to each registrant.)*

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

We are contractually required to operate a power generation facility that we have agreed to lease but the energy sales market for the facility's excess energy is over-supplied. *(Applies to AEP.)*

We have agreed to lease from Juniper Capital L.P. a non-regulated merchant power generation facility ("Facility") near Plaquemine, Louisiana. We sublease the Facility to Dow. We operate the Facility for Dow. Dow uses a portion of the energy produced by the Facility and sells the excess power to us. We have agreed to sell up to all of the excess 800 MW to a third party at a price that is currently in excess of market. This agreement is now being litigated. If it is unenforceable, we will be required to find new purchasers for up to 800 MW. There can be no assurance that this power will be sold at prices that will exceed our costs to produce it. If that were the case, as a result of our obligations to Dow, we would be required to operate the Facility at a loss.

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

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

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

We do not fully hedge against price changes in commodities. *(Applies to each registrant.)*

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

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

We are exposed to losses resulting from the bankruptcy of Enron Corp. *(Applies to AEP, except for last paragraph, which applies to each registrant.)*

In 2002, certain of our subsidiaries filed claims against Enron Corp. ("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 Houston Pipe Line Company ("HPL") from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy.

Cushion gas use 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 required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America ("BOA") and certain other banks (together with BOA, "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. We are currently litigating the rights to the cushion gas.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. In January 2005 we sold a 98% controlling interest in HPL, including the Bammel gas storage facility. We indemnified the purchaser for damages, if any, arising from the litigation with BOA.

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 AEP subsidiaries. The parties are currently in non-binding 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 non-binding court-sponsored mediation. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Potential for disruption exists if the delay of a FERC market power mitigation order is lifted. *(Applies to each registrant.)*

In July 2004, the FERC issued an order directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. We have presented evidence to FERC to demonstrate that we do not possess market power in geographic areas where we sell wholesale power. In a December 2004 order, FERC found that AEP passed the screens in PJM and ERCOT, but not in the SPP area. Because AEP did not pass the market share screen in SPP, FERC initiated a proceeding under Section 206 of the FPA 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. In February 2005 AEP filed with the FERC revisions to its market-based rate tariffs that cap the rates of wholesale power that AEP delivers within its control area of the SPP. We are unable to predict the timing or impact of any further action by the FERC.

CLASSES OF SERVICE

The principal classes of service from which the public utility subsidiaries of AEP derive revenues and the amount of such revenues during the year ended December 31, 2004 are as follows:

Description	AEP System(a)	APCo	CSPCo	I&M	KPCo
	(in thousands)				
Utility Operations:					
Retail Sales					
Residential Sales	$3,249,000	$635,905	$522,871	$367,015	$128,982
Commercial Sales	2,326,000	323,623	467,628	288,046	75,584
Industrial Sales	2,051,000	349,674	131,129	342,622	109,767
Total Other Retail Sales	97,000	41,735	15,328	6,482	1,009
Total Retail	7,723,000	1,350,937	1,136,956	1,004,165	315,342
Wholesale					
System Sales & Transmission	2,330,000	296,877	168,757	343,620	69,023
Risk Management Realized	73,000	18,120	8,029	14,473	7,687
Risk Management Mark-to-Market	(48,000)	192	5,563	-	-
Total Wholesale	2,355,000	315,189	182,349	358,093	76,710
Other Operating Revenues	495,000	65,493	34,161	38,148	16,971
Sales to Affiliates	-	216,563	80,115	261,174	41,590
Gross Utility Operating Revenues	10,573,000	1,948,182	1,433,581	1,661,580	450,613
Provision for Rate Refund	(60,000)	-	-	--	-
Net Utility Operations	10,513,000	1,948,182	1,433,581	1,661,580	450,613
Investments – Gas Operations	3,064,000	-	-	-	-
Investments – Other	480,000	-	-	-	-
Total Revenues	$14,057,000	$1,948,182	$1,433,581	$1,661,580	$450,613

Description	OPCo	PSO	SWEPCo	TCC(b)	TNC(b)
	(in thousands)				
Utility Operations:					
Retail Sales					
Residential Sales	$471,515	$395,571	$331,478	$216,954	$56,033
Commercial Sales	312,264	272,583	280,244	162,487	28,300
Industrial Sales	534,800	256,944	205,948	35,129	8,301
Total Other Retail Sales	8,559	92,325	6,220	9,064	11,386
Total Retail	1,327,138	1,017,423	823,890	423,634	104,020
Wholesale					
System Sales & Transmission	250,001	(7,230)	122,798	636,621	307,926
Risk Management Realized	10,289	13	(267)	234	503
Risk Management Mark-to-Market	9,002	--	571	3,628	1,528
Total Wholesale	269,292	(7,217)	123,102	640,483	309,957
Other Operating Revenues	58,451	26,625	76,124	127,010	37,664
Sales to Affiliates	581,515	10,690	71,190	47,039	51,680
Gross Utility Operating Revenues	2,236,396	1,047,521	1,094,306	1,238,166	503,321
Provision for Rate Refund	-	-	(6,960)	(62,900)	(11,176)
Net Utility Operations	2,236,396	1,047,521	1,087,346	1,175,266	492,145
Investments – Gas Operations	-	-	-	-	-
Investments – Other	-	-	-	-	-
Total Revenues	$2,236,396	$1,047,521	$1,087,346	$1,175,266	$492,145

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated, including AEGCo's total revenues of $241,788,000 for the year ended December 31, 2004, all of which resulted from its wholesale business, including its marketing and trading of power.

(b) TCC and TNC wire sales to REPs moved to retail classes of customer.

HOLDING COMPANY REGULATION

The provisions of PUHCA are administered by the SEC. PUHCA regulates many aspects of a registered holding company system, such as the AEP System. PUHCA limits the operations of a registered holding company system to a single integrated public utility system and such other businesses as are incidental or necessary to the operations of the system. In addition, PUHCA governs, among other things, financings, sales or acquisitions of utility assets and intra-system transactions.

PUHCA and the rules and orders of the SEC currently require that transactions between associated companies in a registered holding company system be performed at cost, with limited exceptions. Over the years, the AEP System has developed numerous affiliated service, sales and construction relationships and, in some cases, invested significant capital and developed significant operations in reliance upon the ability to recover its full costs under these provisions.

Legislation has since been introduced in numerous sessions of Congress that would repeal PUHCA, but no such legislation has passed.

AEP-CSW MERGER

On June 15, 2000, a wholly owned merger subsidiary of AEP merged with and into CSW (now known as AEP Utilities, Inc.). As a result, CSW became a wholly owned subsidiary of AEP. The four wholly owned public utility subsidiaries of CSW—PSO, SWEPCo, TCC and TNC—became indirect wholly owned public utility subsidiaries of AEP as a result of the merger. The merger was approved by the FERC and the SEC.

On January 18, 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to properly explain how the merger met the requirements of PUHCA and remanded the case to the SEC for further review. The court held that the SEC had not adequately explained its conclusions that the merger met PUHCA requirements that the merging entities be "physically interconnected" and that the combined entity was confined to a "single area or region." A hearing was held January 10, 2005 before an ALJ. An initial decision is expected from the ALJ later this year. The SEC will have the opportunity to review the initial decision.

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

FINANCING

General

Companies within the AEP System generally use short-term debt to finance working capital needs, acquisitions and construction. The companies periodically issue long-term debt to reduce short-term debt. In recent history short-term debt has been provided by AEP's commercial paper program and revolving credit facilities. Proceeds were made available to subsidiaries under the AEP corporate borrowing program. Throughout 2004, AEP was successful in accessing the commercial paper market. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity.

AEP's revolving credit agreements (which backstop the commercial paper program) include covenants and events of default typical for this type of facility, including a maximum debt/capital test and a $50 million cross-acceleration provision. At December 31, 2004, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreements. A voluntary bankruptcy or insolvency would be considered an immediate termination event. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2004 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to AEP's credit agreements.

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

Credit Ratings

In 2004, AEP executives met with representatives of the rating agencies to review AEP and its registrant subsidiaries' historical and forecasted financial condition, operations and other matters.

In August 2004, Moody's placed AEP on positive outlook. In July 2004, S&P upgraded the senior secured ratings of PSO and SWEPCo to A- from BBB. To date, S&P has not changed the ratings of AEP or any other of its rated subsidiaries. Fitch did not change the ratings of AEP or its rated subsidiaries during 2004.

The senior secured ratings on certain of AEP's rated subsidiaries will be removed where secured debt no longer exists.

See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2004 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to the credit ratings of the registrants other than AEGCo.

ENVIRONMENTAL AND OTHER MATTERS

General

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

- The CAA and CAAA and state laws and regulations (including State Implementation Plans) that require compliance, obtaining permits and reporting as to air emissions. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *The Current Air Quality Regulatory Framework.*

- Litigation with the federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating plants required additional permitting or pollution control technology. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *The Current Air Quality Regulatory Framework* and *New Source Review Litigation* and Note 7 to the consolidated financial statements entitled *Commitments and Contingencies*, included in the 2004 Annual Reports, for further information.

- Rules issued by the EPA and certain states that require substantial reductions in SO_2, mercury and NOx emissions, some of which became effective in 2003. The remaining compliance dates and proposals would take effect periodically through as late as 2018. AEP is installing (or has installed) emission control technology and is taking other measures to comply with required reductions. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Future Reduction Requirements for NOx, SO_2 and Hg* and *Estimated Air Quality Investments* and Note 7 to the consolidated financial statements entitled *Commitments and Contingencies*, included in the 2004 Annual Reports under the heading entitled *NOx Reductions* for further information.

- CERCLA, which imposes upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites, costs for environmental remediation. AEP does not, however, anticipate that any of its currently identified CERCLA-related issues will result in material costs or penalties to the AEP System. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2004 Annual Reports, under the heading entitled *Superfund and State Remediation* for further information.

- The Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits. In July 2004, the EPA adopted a new Clean Water Act rule to reduce the number of fish and other aquatic organisms killed at once-through cooled power plants. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2004 Annual Reports, under the heading entitled *Clean Water Act Regulation* for additional information.

- Solid and hazardous waste laws and regulations, which govern the management and disposal of certain wastes. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion byproducts, which the EPA has determined are not hazardous waste governed subject to RCRA.

In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2004 Annual Reports, under the heading entitled *Environmental Matters* for information on current environmental issues.

If our expenditures for pollution control technologies, replacement generation and associated operating costs are not recoverable from customers through regulated rates (in regulated jurisdictions) or market prices (in deregulated jurisdictions), those costs could adversely affect future results of operations and cash flows, and possibly financial condition.

The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System.

See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters* and Note 7 to the consolidated financial statements entitled *Commitments and Contingencies*, included in the 2004 Annual Reports, for further information with respect to environmental matters.

Environmental Investments

Investments related to improving AEP System plants' environmental performance and compliance with air and water quality standards during 2003 and 2004 and the current estimate for 2005 are shown below. Substantial investments in addition to the amounts set forth below are expected by the System in future years in connection with the modification and addition of facilities at generating plants for environmental quality controls in order to comply with air and water quality standards which have been or may be adopted. Future investments could be significantly greater if litigation regarding whether AEP properly installed emission control equipment on its plants is resolved against any AEP subsidiaries or emissions reduction requirements are accelerated or otherwise become more onerous. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Future Reduction Requirements for NOx, SO_2 and Hg* and *Estimated Air Quality Investments*; and Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies*, included in the 2004 Annual Reports, for more information regarding this litigation and environmental expenditures in general.

	2003 Actual	2004 Actual	2005 Estimate
		(in thousands)	
AEGCo	$11,800	$6,500	$2,100
APCo	70,600	165,800	309,600
CSPCo	31,400	26,600	23,400
I&M	14,900	11,900	82,300
KPCo	40,500	2,900	8,500
OPCo	40,000	136,400	485,400
PSO	1,700	100	500
SWEPCo	3,200	4,100	24,400
TCC	500	0	0
TNC	2,600	0	400
AEP System	$217,200	$354,300	$936,600

Electric and Magnetic Fields

EMF are found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF are created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring, and appliances.

A number of studies in the past several years have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, none has produced any conclusive evidence that EMF does or does not cause adverse health effects.

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

UTILITY OPERATIONS

GENERAL

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

ELECTRIC GENERATION

Facilities

AEP's public utility subsidiaries own approximately 34,500 MW of domestic generation. See *Deactivation and Disposition of Generating Facilities* for a discussion of planned and completed sales of certain of AEP's generating facilities. Pursuant to regulatory orders, the AEP public utility subsidiaries operate their generating facilities as a single interconnected and coordinated electric utility system. See *Item 2 — Properties* for more information regarding AEP's generation capacity.

AEP Power Pool and CSW Operating Agreement

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio." The Interconnection Agreement has been approved by the FERC.

The member-load ratio is calculated monthly by dividing such company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all east zone operating companies. As of December 31, 2004, the member-load ratios were as follows:

	Peak Demand (MW)	Member-Load Ratio (%)
APCo	6,298	30.7
CSPCo	3,623	17.6
I&M	4,051	19.8
KPCo	1,478	7.2
OPCo	5,059	24.7

Although customer choice was adopted in Ohio in 2001, CSPCo and OPCo plan to remain functionally separated through at least December 31, 2008 as authorized by their rate stabilization plan approved by the PUCO. See *Management's Financial Discussion and Analysis and Financial Condition,* under the heading entitled *Regulatory Matters, Ohio* included in the 2004 Annual Reports and Note 6 to the consolidated financial statements, entitled *Customer Choice and Industry Restructuring*, included in the 2004 Annual Reports, for more information.

The following table shows the net (credits) or charges allocated among the parties under the Interconnection Agreement and AEP System Interim Allowance Agreement during the years ended December 31, 2002, 2003 and 2004:

	2002	2003	2004
		(in thousands)	
APCo	$127,000	$218,000	$239,400
CSPCo	267,000	276,800	284,900
I&M	(113,600)	(118,800)	(141,500)
KPCo	46,500	38,400	31,600
OPCo	(326,900)	(414,400)	(414,400)

PSO, SWEPCo, TCC, TNC, and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which has been approved by the FERC. The CSW Operating Agreement requires the west zone public utility subsidiaries to maintain adequate annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other AEP west zone public utility subsidiaries as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are shared based on the amount of energy each west zone public utility subsidiary contributes that is sold to third parties. Upon the sale of its generation assets, TCC will no longer supply generating capacity under the CSW Operating Agreement.

The following table shows the net (credits) or charges allocated among the parties under the CSW Operating Agreement during the years ended December 31, 2002, 2003 and 2004:

	2002	2003	2004
		(in thousands)	
PSO	$53,700	$44,000	$55,000
SWEPCo	(67,800)	(46,600)	(59,800)
TCC	(15,400)	(29,500)	1,100
TNC	29,500	32,100	3,700

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any public utility subsidiary is primarily sold to customers (or in the case of the ERCOT area of Texas, REPs) by such public utility subsidiary at rates approved (other than in the ERCOT area of Texas) by the public utility commission in the jurisdiction of sale. In Ohio and Virginia, such rates are based on a statutory formula as those jurisdictions transition to the use of market rates for generation. See *Regulation — Rates.*

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

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

Risk Management and Trading

As agent for AEP's public utility subsidiaries, AEPSC sells excess power into the market and engages in power and natural gas risk management and trading activities focused in regions in which AEP traditionally operates. These activities primarily involve the purchase and sale of electricity (and to a lesser extent, natural gas) under physical forward contracts at fixed and variable prices. These contracts include physical transactions, over-the-counter swaps and exchange-traded futures and options. The majority of physical forward contracts are typically settled by entering into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges. Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2004, counterparties have posted approximately $98 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries had posted approximately $2 million with counterparties). Since open trading contracts are valued based on changes in market power prices, exposures change daily.

Fuel Supply

The following table shows the sources of power generated by the AEP System:

	2002	2003	2004
Coal	78%	80%	83%
Natural Gas	8%	7%	5%
Nuclear	11%	9%	12%
Hydroelectric and other	3%	4%	1%

Variations in the generation of nuclear power are primarily related to refueling and maintenance outages. Variations in the generation of natural gas power are primarily related to the availability of cheaper alternatives to fulfill certain power requirements and the deactivation or sale of certain gas-fired plants owned by TCC and TNC. Price increases in one or more fuel sources relative to other fuels generally result in increased use of other fuels.

Coal and Lignite: AEP's public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations, short-term, and spot agreements with various producers and coal trading firms. The price for most coal fuels has increased resulting in a trend that may continue. Management has responded to increases in the price of coal by rebalancing the coal used in its generating facilities with products from different coal regions and sources of differing heat rates and sulfur content. This rebalancing is an ongoing process that is expected to continue. Management believes, but cannot provide assurances that, AEP's public utility subsidiaries will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. See *Investments-Other* for a discussion of AEP's coal marketing and transportation operations.

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

	2002	2003	2004
Total coal delivered to AEP operated plants (thousands of tons)	76,442	76,042	71,778
Average price per ton of spot-purchased coal	$27.06	$28.91	$33.83

The coal supplies at AEP System plants vary from time to time depending on various factors, including customers' usage of electric power, space limitations, the rate of consumption at particular plants, labor issues and weather conditions which may interrupt deliveries. At December 31, 2004, the System's coal inventory was approximately 31 days of normal usage. This estimate assumes that the total supply would be utilized through the operation of plants that use coal most efficiently.

In cases of emergency or shortage, system companies have developed programs to conserve coal supplies at their plants. Such programs have been filed and reviewed with officials of federal and state agencies and, in some cases, the relevant state regulatory agency has prescribed actions to be taken under specified circumstances by System companies, subject to the jurisdiction of such agency.

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

Natural Gas: Through its public utility subsidiaries, AEP consumed over 94 billion cubic feet of natural gas during 2004 for generating power. A majority of the natural gas-fired power plants are connected to at least two pipelines, which allows greater access to competitive supplies and improves reliability. A portfolio of long-term, monthly and seasonal firm purchase and transportation agreements (that are entered into on a competitive basis and based on market prices) supplies natural gas requirements for each plant.

Nuclear: I&M and STPNOC have made commitments to meet their current nuclear fuel requirements of the Cook Plant and STP, respectively. Steps currently are being taken, based upon the planned fuel cycles for the Cook Plant, to review and evaluate I&M's requirements for the supply of nuclear fuel. I&M has made and will make purchases of uranium in various forms in the spot, short-term, and mid-term markets until it decides that deliveries under long-term supply contracts are warranted. TCC and the other STP participants have entered into contracts with suppliers for (i) 100% of the uranium concentrate sufficient for the operation of both STP units through spring 2011 and (ii) 100% of the uranium concentrate needed for STP through spring 2011. See *Deactivation and Disposition of Generation Facilities* for more information about TCC's interest in STP.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M has completed modifications to its spent nuclear fuel storage pool. AEP anticipates that the Cook Plant has storage capacity to permit normal operations through 2012. STP has on-site storage facilities with the capability to store the spent nuclear fuel generated by the STP units over their licensed lives.

Nuclear Waste 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 dispose of spent nuclear fuel and decommission and decontaminate the plants safely. The ultimate cost of retiring the Cook Plant and STP may be materially different from estimates and funding targets as a result of the:

- Type of decommissioning plan selected;
- Escalation of various cost elements (including, but not limited to, general inflation);
- Further development of regulatory requirements governing decommissioning;
- Limited availability to date of significant experience in decommissioning such facilities;
- Technology available at the time of decommissioning differing significantly from that assumed in studies;
- Availability of nuclear waste disposal facilities;
- Availability of a Department of Energy facility for permanent storage of spent nuclear fuel; and
- Approval of the Cook Plant's license extension.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant and STP will not be significantly different than current projections. See *Deactivation and Disposition of Generation Facilities* for more information about TCC's interest in STP.

See *Management's Financial Discussion and Analysis of Results of Operations* and Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies*, included in the 2004 Annual Reports, for information with respect to nuclear waste and decommissioning and related litigation.

Low-Level Radioactive Waste: The LLWPA mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan and Texas do not currently have disposal sites for such waste available. AEP cannot predict when such sites may be available, but South Carolina and Utah operate low-level radioactive waste disposal sites and accept low-level radioactive waste from Michigan and Texas. AEP's access to the South Carolina facility is currently allowed through the end of fiscal year 2008. There is currently no set date limiting AEP's access to the Utah facility. See *Deactivation and Disposition of Generation Facilities* for more information about TCC's interest in STP.

Deactivation and Disposition of Generation Facilities

Pursuant to ERCOT's approval, AEP deactivated 16 gas-fired power plants (8 TCC plants and 8 TNC plants). Separately, TCC conducted an auction to sell all of its generation facilities in Texas to establish the market value of the assets and TCC's stranded costs in accordance with the Texas Act. See *Texas Regulatory Assets and Stranded Cost Recovery and Post-Restructuring Wires Charges.* The competitive bidding process began in June 2003 after the PUCT issued a rule confirming TCC's ability to establish the value of its generation assets and amount of stranded costs by selling the generation assets. The PUCT engaged a consultant and designated a team to monitor the auction and advise TCC on the sale of its generating assets, including requirements of the Texas Act for establishing stranded costs.

The assets had a generating capacity of 4,497 MW and included the eight deactivated gas-fired generating plants, one coal-fired plant, TCC's interest in Oklaunion Power Station, a hydroelectric facility and TCC's interest in STP. TCC has entered into agreements to sell its 7.8% share of Oklaunion Power Station and its 25.2% share in STP and sold the remaining generation assets in July 2004. See Notes 6 and 10 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring* and *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held For Sale and Assets Held and Used,* included in the 2004 Annual Reports, for more information on the disposition of TCC generation facilities.

Structured Arrangements Involving Capacity, Energy, and Ancillary Services

In January 2000, OPCo and NPC, an affiliate of Buckeye, entered into an agreement relating to the construction and operation of a 510 MW gas-fired electric generating peaking facility to be owned by NPC. OPCo is entitled to 100% of the power generated by the facility, and is responsible for the fuel and other costs of the facility through 2005. After 2005, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the facility, and both parties will generally be responsible for the fuel and other costs of the facility.

Certain Power Agreements

AEGCo: Since its formation in 1982, AEGCo's business has consisted of the ownership and financing of its 50% interest in Unit 1 of the Rockport Plant and, since 1989, leasing of its 50% interest in Unit 2 of the Rockport Plant. The operating revenues of AEGCo are derived from the sale of capacity and energy associated with its interest in the Rockport Plant to I&M and KPCo pursuant to unit power agreements, which have been approved by the FERC.

The I&M Power Agreement provides for the sale by AEGCo to I&M of all the capacity (and the energy associated therewith) available to AEGCo at the Rockport Plant. Whether or not power is available from AEGCo, I&M is obligated to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M). When added to amounts received by AEGCo from any other sources, such amounts will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the last of the lease terms of Unit 2 of the Rockport Plant has expired (currently December 2022) unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the capacity (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo the amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement was extended in November 2004 for an additional 18 years and now expires in December 2022.

AEGCo and AEP have entered into a capital funds agreement pursuant to which, among other things, AEP has unconditionally agreed to make cash capital contributions, or in certain circumstances subordinated loans, to AEGCo to the extent necessary to enable AEGCo to (i) maintain such an equity component of capitalization as required by governmental regulatory authorities; (ii) provide its proportionate share of the funds required to permit commercial operation of the Rockport Plant; (iii) enable AEGCo to perform all of its obligations, covenants and agreements under, among other things, all loan agreements, leases and related documents to which AEGCo is or becomes a party (AEGCo Agreements); and (iv) pay all indebtedness, obligations and liabilities of AEGCo (AEGCo Obligations) under the AEGCo Agreements, other than indebtedness, obligations or liabilities owing to AEP. The capital funds agreement will terminate after all AEGCo Obligations have been paid in full.

OVEC: AEP, CSPCo and several unaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP and CSPCo in OVEC is 44.2%. In April 2004, AEP agreed to sell a portion of its shares in OVEC (.73% of OVEC) to Louisville Gas and Electric Company. The sale is expected to close in the first quarter of 2005. Following the sale, the aggregate equity participation of AEP and CSPCo in OVEC will be 43.47%. Until September 1, 2001, OVEC supplied from its generating capacity the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the DOE. The sponsoring companies are now entitled to receive and obligated to pay for all OVEC capacity (approximately 2,200 MW) in proportion to their power participation ratios. The aggregate power participation ratio of APCo, CSPCo, I&M and OPCo is 42.1%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. The Inter-Company Power Agreement (ICPA), which defines the rights of the owners and sets the power participation ratio of each, will expire by its terms on March 12, 2006. An Amended and Restated ICPA has been unanimously approved and executed by the sponsoring companies and OVEC to extend the term of the ICPA for an additional 20 years to March 13, 2026. The aggregate power participation ratio of the AEP entities in the Amended and Restated ICPA is 43.47%. The AEP-affiliated owners of OVEC and the other owners are evaluating the need for environmental investments related to their ownership interests, which may be material.

Buckeye: Transmission service agreements between Buckeye, AEP and other transmission owners provide for the transmission and delivery of power generated by Buckeye at the Cardinal Station. These transmission agreements were made pursuant to the applicable open access transmission tariffs (OATT) of AEP and others. On October 1, 2004, AEP joined PJM, and the Buckeye transmission service over the AEP system was transferred under the PJM OATT. Buckeye is entitled under the Cardinal Station Agreement to receive, and is obligated to pay for, the excess of its maximum one-hour coincident peak demand plus a 15% reserve margin over the 1,226,500 kilowatts of capacity of the generating units which Buckeye currently owns in the Cardinal Station. Such demand, which occurred on January 23, 2003, was recorded at 1,409,726 kilowatts.

ELECTRIC TRANSMISSION AND DISTRIBUTION

General

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

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

AEP Transmission Pool

Transmission Equalization Agreement: APCo, CSPCo, I&M, KPCo and OPCo operate their transmission lines as a single interconnected and coordinated system and are parties to the Transmission Equalization Agreement, dated April 1, 1984, as amended (TEA), defining how they share the costs and benefits associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 KV and above) and certain facilities operated at lower voltages (138 KV and above). The TEA has been approved by the FERC. Sharing under the TEA is based upon each company's "member-load ratio." The member-load ratio is calculated monthly by dividing such company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all east zone operating companies. As of December 31, 2004, the member-load ratios were as follows:

	Peak Demand (MW)	Member-Load Ratio (%)
APCo	6,298	30.7
CSPCo	3,623	17.6
I&M	4,051	19.8
KPCo	1,478	7.2
OPCo	5,059	24.7

The following table shows the net (credits) or charges allocated among the parties to the TEA during the years ended December 31, 2002, 2003 and 2004:

	2002	2003	2004
		(in thousands)	
APCo	$(13,400)	$0	$(500)
CSPCo	42,200	38,200	37,700
I&M	(36,100)	(39,800)	(40,800)
KPCo	(5,400)	(5,600)	(6,100)
OPCo	12,700	7,200	9,700

Transmission Coordination Agreement: PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone public utility subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone public utility subsidiaries have delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the AEP OATT on their behalf. The TCA also provides for the allocation among the west zone public utility subsidiaries of revenues collected for transmission and ancillary services provided under the AEP OATT.

The following table shows the net (credits) or charges allocated among the parties to the TCA during the years ended December 31, 2002, 2003 and 2004:

	2002	2003	2004
		(in thousands)	
PSO	$4,200	$4,200	$ 8,100
SWEPCo	5,000	5,000	13,800
TCC	(3,600)	(3,600)	(12,200)
TNC	(5,600)	(5,600)	(9,700)

Transmission Services for Non-Affiliates: In addition to providing transmission services in connection with their own power sales, AEP's public utility subsidiaries and other System companies also provide transmission services for non-affiliated companies. See *Regional Transmission Organizations.* Transmission of electric power by AEP's public utility subsidiaries is regulated by the FERC.

Coordination of East and West Zone Transmission: AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's east and west zone public utility subsidiaries. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the TEA and the TCA. The System Transmission Integration Agreement contains two service schedules that govern:

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

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

Regional Transmission Organizations

On April 24, 1996, the FERC issued orders 888 and 889. These orders require each public utility that owns or controls interstate transmission facilities to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The orders also require utilities to functionally unbundle their services, by requiring them to use their own tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a *pro-forma* tariff that reflects the Commission's views on the minimum non-price terms and conditions for non-discriminatory transmission service. In addition, the orders require all transmitting utilities to establish an OASIS, which electronically posts transmission information such as available capacity and prices, and require utilities to comply with Standards of Conduct that prohibit utilities' system operators from providing non-public transmission information to the utility's merchant energy employees. The orders also allow a utility to seek recovery of certain prudently incurred stranded costs that result from unbundled transmission service.

In December 1999, FERC issued Order 2000, which provides for the voluntary formation of RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals.

As a condition of FERC's approval in 2000 of AEP's merger with CSW, AEP was required to transfer functional control of its transmission facilities to one or more RTOs. In May 2002, AEP announced an agreement with PJM to pursue terms for its east zone public utility subsidiaries to participate in PJM, a FERC-approved RTO. The AEP East Companies integrated into PJM on October 1, 2004.

SWEPCo and PSO currently intend to transfer functional control of their transmission assets to SPP subject to receipt of appropriate regulatory approvals. In February 2004, the FERC conditionally approved SPP as an RTO. In October 2004, the FERC issued an order granting RTO status to SPP subject to certain filings. The Arkansas Public Service Commission and LPSC have required filings related to SWEPCo's transfer of functional control of transmission facilities to an RTO. The remaining west zone public utility subsidiaries (TCC and TNC) are members of ERCOT.

See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2004 Annual Reports and *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *RTO Formation* for a discussion of public utility subsidiary participation in RTOs.

Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the 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 Midwest ISO and PJM expanded 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 under the RTOs' revenue distribution protocols.

AEP and several other utilities in the Combined Footprint filed a proposal for new rates to become effective December 1, 2004. In November 2004, FERC eliminated the T&O rates and replaced the rates temporarily through March 2006 with a seams elimination cost adjustment (SECA) fees. AEP's East zone public utility subsidiaries received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the last twelve months prior to joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA fees was $171 million. Effective April 2006, all transmission costs that would otherwise be defrayed by T&O rates in the Combined Footprint will be subject to recovery from native load customers of AEP's East zone public utility subsidiaries. At this time, management is unable to predict whether any resultant increase in rates applicable to AEP's internal load will be recoverable on a timely basis from state retail customers. Unless new replacement rates compensate AEP for its lost revenues and any increase in AEP's East zone public utility subsidiaries' transmission expenses from these new rates are fully recovered in retail rates on a timely basis, future results of operations, cash flows and financial condition will be adversely affected. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *FERC Order on Regional Through and Out Rates* for more information.

REGULATION

General

Except for retail generation sales in Ohio, Virginia and the ERCOT area of Texas, AEP's public utility subsidiaries' retail rates and certain other matters are subject to traditional regulation by the state utility commissions. While still regulated, retail sales in Michigan are now made at unbundled rates. See *Electric Restructuring and Customer Choice Legislation* and *Rates*. AEP's subsidiaries are also subject to regulation by the FERC under the FPA. I&M and TCC are subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant and STP, respectively. AEP and certain of its subsidiaries are also subject to the broad regulatory provisions of PUHCA administered by the SEC.

Rates

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

The rates of AEP's public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). In Ohio, Virginia and the ERCOT area of Texas, rates are transitioning from bundled cost-based rates for electric service to unbundled cost-based rates for transmission and distribution service on the one hand, and market pricing for and/or customer choice of generation on the other. In Ohio, the PUCO has approved the rate stabilization plans filed by OPCo and CSPCo which, among other things, address retail generation service rates through December 31, 2008. In Virginia, APCO's base rates are capped, subject to certain adjustments, at their mid-1999 levels until December 31, 2010, or sooner if the VSCC finds that a competitive market for generation exists in Virginia.

Historically, the state regulatory frameworks in the service area of the AEP System reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes. While the historical framework remains in a portion of AEP's service territory, recovery of increased fuel costs through a fuel adjustment clause is no longer provided for in Ohio. Fuel recovery is also limited in the ERCOT area of Texas, but because AEP sold MECPL and MEWTU, there is little impact on AEP of fuel recovery procedures related to service in ERCOT.

The following state-by-state analysis summarizes the regulatory environment of each jurisdiction in which AEP operates. Several public utility subsidiaries operate in more than one jurisdiction.

Indiana: I&M provides retail electric service in Indiana at bundled rates approved by the IURC. While rates are set on a cost-of-service basis, utilities may also generally seek to adjust fuel clause rates quarterly. I&M's base rates were capped through December 31, 2004. Its fuel recovery rate was capped through February 29, 2004. On September 22, 2004, the IURC issued an order extending the interim fuel factor through March 2005, subject to true-up upon resolution of the (previously filed but unexecuted) corporate separation plan. The status of additional base and fuel clause rate caps, subject to certain conditions, is presently under discussion with the parties to a proposed settlement agreement relating to AEP's corporate separation issues.

Ohio: CSPCo and OPCo each operates as a functionally separated utility and provides "default" retail electric service to customers at unbundled rates pursuant to the Ohio Act through December 31, 2005. The PUCO approved the rate stabilization plan filed by CSPCo and OPCo (which, among other things, addresses default retail generation service rates from January 1, 2006 through December 31, 2008). Retail generation rates would be determined consistent with the rate stabilization plan until December 31, 2008. CSPCo and OPCo are and will continue to provide distribution services to retail customers at rates approved by the PUCO. These rates will be frozen (with certain exceptions) from their levels as of December 31, 2005 through December 31, 2008. Transmission services will continue to be provided at rates established by the FERC. See Note 6 to the consolidated financial statements, entitled *Customer Choice and Industry Restructuring*, included in the 2004 Annual Reports, for more information.

Oklahoma: PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is adjusted quarterly and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new quarterly factors are established. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2004 Annual Reports, for information regarding current rate proceedings.

Texas: The Texas Act requires the legal separation of generation-related assets from transmission and distribution assets. TCC and TNC currently operate on a functionally separated basis. In January 2002, TCC and TNC transferred all their retail customers in the ERCOT area of Texas to MECPL, MEWTU and AEP Commercial and Industrial REP (an AEP affiliate). TNC's retail SPP customers were ultimately transferred to Mutual Energy SWEPCo L.P. (an AEP affiliate). TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2004 Annual Reports, for information on current rate proceedings.

In May 2003, the PUCT delayed competition in the SPP area of Texas until at least January 1, 2007. As such, SWEPCo's Texas operations continue to operate and to be regulated as a traditional bundled utility with both base and fuel rates.

Virginia: APCo provides unbundled retail electric service in Virginia. APCo's unbundled generation, transmission (which reflect FERC approved transmission rates) and distribution rates as well as its functional separation plan were approved by the VSCC in December 2001.

The Virginia Act, which was amended in 2004, capped APCO's base rates at their mid-1999 levels until the end of the transition period (now December 31, 2010), or sooner if the VSCC finds that a competitive market for generation exists in Virginia. The Virginia Act permits APCo to seek two changes to its capped rates as follows: one prior to July 1, 2007, and one between July 1, 2007 and December 31, 2010. In addition, as a result of the 2004 amendments, APCo is entitled to annual rate changes to recover the incremental costs it incurs on and after July 1, 2004 for transmission and distribution reliability and compliance with state or federal environmental laws or regulations. The Virginia Act also allows adjustments to fuel rates during the transition period and continues to permit utilities to recover their actual fuel costs, the fuel component of their purchased power costs and certain capacity charges. APCo recovers its generation capacity charges through capped base rates.

West Virginia: APCo and Wheeling Power Company provide retail electric service at bundled rates approved by the WVPSC. A plan to introduce customer choice was approved by the West Virginia Legislature in its 2000 legislative session. However, implementation of that plan was placed on hold pending necessary changes to the state's tax laws in a subsequent session. Those changes have not been made. Management currently believes that implementation of the plan is unlikely.

While West Virginia generally allows for timely recovery of fuel costs, the most recent rate proceeding for both APCo and WPCo resulted in the suspension of their operative fuel clause mechanisms (though they continue to recover a fixed level of fuel costs through bundled rates). APCo and Wheeling Power Company are currently unable to change the current level of fuel cost recovery, though this ability could be reinstated in a future proceeding.

Other Jurisdictions: The public utility subsidiaries of AEP also provide service at regulated bundled rates in Arkansas, Kentucky, Louisiana and Tennessee and regulated unbundled rates in Michigan.

The following table illustrates the current rate regulation status of the states in which the public utility subsidiaries of AEP operate:

Jurisdiction	Status of Base Rates for Power Supply	Status of Base Rates for Energy Delivery	Fuel Clause Rates(7) Status	Fuel Clause Rates(7) System Sales Profits Shared with Ratepayers	Percentage of AEP System Retail Revenues(1)
Ohio	Frozen through 2005(2)	Distribution frozen through 2008(2)	None	Not applicable	32%
Oklahoma	Not capped or frozen	Not capped or frozen	Active	Yes	13%
Texas ERCOT	See footnote 3	Not capped or frozen	Not applicable	Not applicable	8%(3)
Texas SPP	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	4%(3)
Indiana	Extension of freeze is pending(4)	Extension of freeze is pending(4)	Extension of cap is pending(4)	No	11%
Virginia	Capped until as late as 12/31/10(5)	Capped until as late as 12/31/10(5)	Active	No	9%
West Virginia	Not capped or frozen	Not capped or frozen	Suspended (6)	Yes, but suspended	9%
Louisiana	Capped until 6/15/05	Capped until 6/15/05	Active	Yes, above base levels	4%
Kentucky	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	4%
Arkansas	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	3%
Michigan	Not capped or frozen	Not capped or frozen	Active	Yes, in some areas	2%
Tennessee	Not capped or frozen	Not capped or frozen	Active	No	1%

(1) Represents the percentage of revenues from sales to retail customers from AEP utility companies operating in each state to the total AEP System revenues from sales to retail customers for the year ended December 31, 2004.

(2) The PUCO has approved the rate stabilization plan filed by CSPCo and OPCo that begins after the market development period and extends through December 31, 2008 during which OPCo's retail generation rates will increase 7% annually and CSPCo's retail generation rates will increase 3% annually. Distribution rates are frozen, with certain exceptions, through December 31, 2008.

(3) Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs with TCC and TNC providing only regulated delivery services. Retail electric service in the SPP area of Texas is provided by SWEPCo and an affiliated REP.

(4) Capped base rates pursuant to a 1999 settlement with base rate freeze extended pursuant to merger stipulation. The status of additional base and fuel clause rate caps, subject to certain conditions, is presently under discussion and there is an issue as to whether the freeze and cap extend through 2007 under an existing corporate separation stipulation agreement. The interim fuel clause rate cap expires in April 2005.

(5) Legislation passed in 2004 capped base rates until December 31, 2010 and expanded the rate change opportunities to one full rate case (including generation, transmission and distribution) between July 1, 2004 and June 30, 2007 and one additional full rate case between July 1, 2007 and December 31, 2010. The new law also permits APCo to recover, on a timely basis, incremental costs incurred on and after July 1, 2004 for transmission and distribution reliability purposes and to comply with state and federal environmental laws and regulations.

(6) Expanded net energy clause suspended in West Virginia pursuant to a 1999 rate case stipulation, but subject to change in a future proceeding.

(7) Includes, where applicable, fuel and fuel portion of purchased power.

FERC

Under the FPA, FERC regulates rates for interstate sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. FERC regulations require AEP to provide open access transmission service at FERC-approved rates. FERC also regulates unbundled transmission service to retail customers.

Under the FPA, the FERC regulates the sale of power for resale in interstate commerce by (i) approving contracts for wholesale sales to municipal and cooperative utilities and (ii) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. AEP has market-rate authority from FERC, under which most of its wholesale marketing activity takes place. In November 2001, the FERC issued an order in connection with its triennial review of AEP's market based pricing authority requiring (i) certain actions by AEP in connection with its sales and purchases within its control area and (ii) posting of information related to generation facility status on AEP's website. AEP appealed that order, and the FERC issued an order delaying the effective date of the order. This was done in connection with the FERC's adoption of a new test called supply management assessment (SMA).

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 unaffiliated 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. As part of PJM, AEP 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 a proceeding under Section 206 of the FPA in which AEP is rebuttably presumed to possess market power in SPP. Consequently, our revenues from sales within our control area of the 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. In February 2005 AEP filed with the FERC revisions to its market-based rate tariffs that cap the rates of wholesale power that AEP delivers within its control area of the SPP. We are unable to predict the timing or impact of any further action by the FERC.

ELECTRIC RESTRUCTURING AND CUSTOMER CHOICE LEGISLATION

Certain states in AEP's service area have adopted restructuring or customer choice legislation. In general, this legislation provides for a transition from bundled cost-based rate regulated electric service to unbundled cost-based rates for transmission and distribution service and market pricing for the supply of electricity with customer choice of supplier. At a minimum, this legislation allows retail customers to select alternative generation suppliers. Electric restructuring and/or customer choice began on January 1, 2001 in Ohio and on January 1, 2002 in Michigan, Virginia and the ERCOT area of Texas. Electric restructuring in the SPP area of Texas has been delayed by the PUCT until at least 2007. AEP's public utility subsidiaries operate in both the ERCOT and SPP areas of Texas.

Implementation of legislation enacted in West Virginia to allow retail customers to choose their electricity supplier is unlikely. In order for West Virginia's choice plan to become effective, tax legislation must be passed to preserve pre-legislation levels of funding for state and local governments. Because such legislation has not been passed and because legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities, management currently believes that implementation of the plan is unlikely. In February 2003, Arkansas repealed its restructuring legislation.

See Note 5 to the consolidated financial statements, entitled *Effects of Regulation*, included in the 2004 Annual Reports, for a discussion of the effect of restructuring and customer choice legislation on accounting procedures. See Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring* for additional information.

Michigan Customer Choice

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Rates for retail electric service for I&M's Michigan customers were unbundled (though they continue to be regulated) to allow customers the ability to evaluate the cost of generation service for comparison with other suppliers. At December 31, 2004, none of I&M's Michigan customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Ohio Restructuring

The Ohio Act requires vertically integrated electric utility companies that offer competitive retail electric service in Ohio to separate their generating functions from their transmission and distribution functions. Following the market development period (which will terminate no later than December 31, 2005), retail customers will receive distribution and, where applicable, 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. CSPCo and OPCo filed a rate stabilization plan with the PUCO that, among other things, addresses default generation service rates from January 1, 2006 through December 31, 2008. See *Regulation—FERC* for a discussion of FERC regulation of transmission rates and *Regulation—Rates—Ohio* for a discussion of the impact of restructuring on distribution rates. The PUCO approved the rate stabilization plan filed by CSPCo and OPCo, with certain modifications. The Commission authorized CSPCo and OPCo to remain functionally separated through the end of that three-year period.

Texas Restructuring

Signed into law in June of 1999, the Texas Act substantially amended the regulatory structure governing electric utilities in Texas in order to allow retail electric competition for all customers. Among other things, the Texas Act:

- gave Texas customers the opportunity to choose their REP beginning January 1, 2002 (delayed until at least 2007 in the SPP portion of Texas),
- required each utility to legally separate into a REP, a power generation company, and a transmission and distribution utility, and

- required that REPs provide electricity at generally unregulated rates, except that the prices that may be charged to residential and small commercial customers by REPs affiliated with a utility within the affiliated utility's service area are set by the PUCT, at the PTB, until certain conditions in the Texas Act are met.

The Texas Act provides each affected utility an opportunity to recover its generation related regulatory assets and stranded costs resulting from the legal separation of the transmission and distribution utility from the generation facilities and the related introduction of retail electric competition. Regulatory assets consist of the Texas jurisdictional amount of generation-related regulatory assets and liabilities in the audited financial statements as of December 31, 1998. Stranded costs consist of the positive excess of the net regulated book value of generation assets (as of December 31, 2001) over the market value of those assets, taking specified factors into account, as ultimately determined in a PUCT true-up proceeding.

For a discussion of (i) regulatory assets and stranded costs subject to recovery by TCC and (ii) rate adjustments made after implementation of restructuring to allow recovery of certain costs by or with respect to TCC and TNC, see *Texas Regulatory Asset and Stranded Cost Recovery and Post-Restructuring Wires Charges* and Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring.*

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 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.

Texas Regulatory Assets And Stranded Cost Recovery And Post-Restructuring Wires Charges

TCC may recover generation-related regulatory assets and plant-related stranded costs. Regulatory assets consist of the Texas jurisdictional amount of generation-related regulatory assets and liabilities in the audited financial statements as of December 31, 1998. Plant-related stranded costs consist of the positive excess of the net regulated book value of generation assets (as of December 31, 2001) over the market value of those assets, taking specified factors into account. The Texas Act allows alternative methods of valuation to determine the fair market value of generation assets, including outright sale, full and partial stock valuation and asset exchanges, and also, for nuclear generation assets, the excess cost over market (ECOM) model. Carrying costs on stranded costs are also allowed to be recovered beginning January 1, 2002.

TCC's 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 ECOM model for 2002 and 2003 (wholesale capacity auction true-up),
- 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 the above 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.

TCC's net true-up regulatory assets (liabilities) recorded at December 31, 2004 is set forth in the following table.

TCC's net true-up regulatory assets (liabilities)

	(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)
Deferred Over-recovered Fuel Balance	(212)
Net Other Recoverable True-up Amounts	287
Total Recorded Net True-up Regulatory Asset (Liability)	$ 1,648

For a more complete discussion of recovery of regulatory assets and stranded costs in Texas, see Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring*, included in the 2004 Annual Reports.

The Texas Act further permits utilities to establish a special purpose entity to issue securitization bonds for the recovery of generation-related regulatory assets and, after the true-up proceeding, the amount of plant-related stranded costs and remaining generation-related regulatory assets not previously securitized. Securitization bonds allow for regulatory assets and plant-related stranded costs to be refinanced with recovery of the bond principal and financing costs ensured through a non-bypassable rate surcharge by the regulated transmission and distribution utility over the life of the securitization bonds. Any plant-related stranded costs or generation-related regulatory assets not recovered through the sale of securitization bonds may be recovered through a separate non-bypassable competitive transition charge to transmission and distribution customers.

For a discussion of recovery of regulatory assets and stranded costs in Ohio and Virginia, see Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring*, included in the 2004 Annual Reports.

COMPETITION

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

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

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

SEASONALITY

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

INVESTMENTS

GAS OPERATIONS

During 2004 we sold our interests in Louisiana Intrastate Gas and Jefferson Island Storage & Hub. In January 2005, we sold a 98% controlling interest in HPL and related assets. We currently retain a 2% ownership interest in HPL and will provide certain transitional services to the buyer. See Notes 10 and 19 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used* and *Subsequent Events (unaudited)*, respectively, included in the 2004 Annual Reports for more information. Before these sales, our gas marketing operations had been significantly curtailed. As a result of these sales, management anticipates that our gas marketing operations will be limited to managing our obligations with respect to the gas transactions entered into before these sales.

UK OPERATIONS

Through certain subsidiaries, AEP operated and owned 4,000 MW of power generation facilities in the UK. These assets and related commodities contracts were sold to Scottish and Southern Energy plc in the third quarter of 2004. AEP also sold its 50 percent interest in South Coast Power Limited to co-owner Scottish Power Generation Limited in the third quarter of 2004. See Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used*, included in the 2004 Annual Reports.

OTHER

General

Through certain subsidiaries, AEP conducts certain business operations other than those included in other segments in which it uses and manages a portfolio of energy-related assets. Consistent with its business strategy, AEP intends to dispose of some of these non-core assets. The assets currently used and managed include:

- 791 MW of domestic and 605 MW of international power generation facilities (of which its ownership is approximately 551 MW and 302 MW, respectively);
- Undeveloped and formerly operated coal properties and related facilities; and
- Barge, rail and other fuel transportation related assets.

These operations include the following activities:

- Entering into long-term transactions to buy or sell capacity, energy, and ancillary services of electric generating facilities at various locations in North America.
- Holding various properties, coal reserves and royalty interests and reclaiming formerly operated mining properties in Colorado, Indiana, Kentucky, Louisiana, Ohio, Texas, Utah and West Virginia; and

- Through MEMCO Barge Line Inc., transporting coal and dry bulk commodities, primarily on the Ohio, Illinois, and Lower Mississippi rivers for AEP, as well as unaffiliated customers. Through subsidiaries, AEP owns or leases 7,065 railcars, 2,230 barges, 53 towboats and a coal handling terminal with 20 million tons of annual capacity.

AEP has in the past three years written down the value of certain of these investments. See *Management's Financial Discussion and Analysis of Results of Operations* and Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used,* included in the 2004 Annual Reports.

Dow Chemical Cogeneration Facility

Pursuant to an agreement with Dow, AEP constructed a 900 MW cogeneration facility at Dow's chemical facility in Plaquemine, Louisiana that achieved commercial operation status on March 18, 2004. AEP's subsidiary, OPCo, has been taking 100% of the facility's capacity and energy over Dow's requirements and contracted to sell the power from this facility for twenty years to Tractebel. The power supply contract with Tractebel is in dispute and the power from this plant is currently sold on the market. See Notes 7 and 10 to the consolidated financial statements, entitled *Commitments and Contingencies* and *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used,* respectively, included in the 2004 Annual Reports, for more information.

ITEM 2. PROPERTIES

GENERATION FACILITIES

GENERAL

At December 31, 2004, the AEP System owned (or leased where indicated) generating plants with net power capabilities (east zone public utility subsidiaries-winter rating; west zone public utility subsidiaries-summer rating) shown in the following table:

Company	Stations		Coal MW	Natural Gas MW	Hydro MW	Nuclear MW	Lignite MW	Oil MW	Total MW
AEGCo	1	(a)	1,300						1,300
APCo	16	(b)	5,073		798				5,871
CSPCo	5	(e)	2,595						2,595
I&M	9	(a)	2,295		11	2,143			4,449
KPCo	1		1,060						1,060
OPCo	8	(b)(f)	8,472		48				8,520
PSO	8	(c)	1,018	3,139				25	4,182
SWEPCo	9		1,848	1,797			842		4,487
TCC	2	(c)(d)(g)	54			630			684
TNC	11	(c)	377	999 (h)				10	1,386
Totals:	65		24,092	5,935	857	2,773	842	35	34,534

(a) Unit 1 of the Rockport Plant is owned one-half by AEGCo and one-half by I&M. Unit 2 of the Rockport Plant is leased one-half by AEGCo and one-half by I&M. The leases terminate in 2022 unless extended.

(b) Unit 3 of the John E. Amos Plant is owned one-third by APCo and two-thirds by OPCo.

(c) PSO, TCC and TNC, along with two unaffiliated companies, jointly own the Oklaunion power station. Their respective ownership interests are reflected in this table.

(d) Reflects TCC's interest in STP.

(e) CSPCo owns generating units in common with CG&E and DP&L. Its ownership interest of 1,330 MW is reflected in this table.

(f) The scrubber facilities at the General James M. Gavin Plant are leased. OPCo may terminate the lease as early as 2010.

(g) See *Item 1 — Utility Operations — Electric Generation — Deactivation and Disposition of Generation Facilities* for a discussion of TCC's planned disposition of all its generation facilities.

(h) TNC's gas fired generation is deactivated.

In addition to the generating facilities described above, AEP has ownership interests in other electrical generating facilities, both foreign and domestic. Information concerning these facilities at December 31, 2004 is listed below.

Facility	Fuel	Location	Capacity Total MW	Ownership Interest	Status
Desert Sky Wind Farm	Wind	Texas	161	100%	Exempt Wholesale Generator(1)
Sweeney	Natural gas	Texas	480	50%	Qualifying Facility(2)
Trent Wind Farm	Wind	Texas	150	100%	Exempt Wholesale Generator(1)
Total U.S.			791		
Bajio	Natural gas	Mexico	605	50%	Foreign Utility Company(1)
Total			1,396		

(1) As defined under PUHCA
(2) As defined under the Public Utility Regulatory Policies Act of 1978

See Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used,* included in the 2004 Annual Reports, for a discussion of AEP's planned use and/or disposition of independent power producer and foreign generation assets.

COOK NUCLEAR PLANT AND STP

The following table provides operating information relating to the Cook Plant and STP.

	Cook Plant		STP (a)	
	Unit 1	**Unit 2**	**Unit 1**	**Unit 2**
Year Placed in Operation	1975	1978	1988	1989
Year of Expiration of NRC License (b)	2014	2017	2027	2028
Nominal Net Electrical Rating in Kilowatts	1,036,000	1,107,000	1,250,600	1,250,600
Net Capacity Factors (c)				
2004	97.0%	81.6%	100.8%	93.7%
2003 (c)	73.5%	74.5%	62.0%	81.2%
2002	86.6%	80.5%	99.2%	75.0%
2001 (d)	87.3%	83.4%	94.4%	87.1%

(a) Reflects total plant. TCC has an ownership interest in STP of approximately 25.2%. TCC has entered into an agreement to sell this interest and the sale is expected to be completed in 2005.

(b) AEP has filed to extend the licenses at the Cook Plant.

(c) The capacity factors for both units of the Cook Plant were reduced in 2003 due to an unplanned maintenance outage to implement upgrades to the traveling water screens system following an alewife fish intrusion. The capacity factors for the STP units were reduced due to an unplanned outage for BMI repairs on Unit 1 and an unplanned outage for turbine repairs on Unit 2.

(d) The capacity factor for both units of the Cook Plant was significantly reduced in 2001 due to an unplanned dual maintenance outage in September 2001 to implement design changes that improved the performance of the essential service water system.

(e) Cook Plant 2004 Net Capacity Factor values reflect Nominal Net Electrical Rating in Kilowatts of 1,036,000 (Unit 1) and 1,107,000 (Unit 2). However, Cook Plant 2003 and earlier Net Capacity Factor values reflect previous Nominal Net Electrical Rating in Kilowatts of 1,020,000 (Unit 1) and 1,090,000 (Unit 2).

Costs associated with the operation (excluding fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. I&M and TCC may also incur costs and experience reduced output at Cook Plant and STP, respectively, because of the design criteria prevailing at the time of construction and the age of the plant's systems and equipment. Nuclear industry-wide and Cook Plant and STP initiatives have contributed to slowing the growth of operating and maintenance costs at these plants. However, the ability of I&M and TCC to obtain adequate and timely recovery of costs associated with the Cook Plant and STP, respectively, including replacement power, any unamortized investment at the end of the useful life of the Cook Plant and STP (whether scheduled or premature), the carrying costs of that investment and retirement costs, is not assured. See *Item 1 — Utility Operations — Electric Generation — Planned Deactivation and Planned Disposition of Generation Facilities* for a discussion of TCC's planned disposition of its interest in STP.

TRANSMISSION AND DISTRIBUTION FACILITIES

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

	Total Overhead Circuit Miles of Transmission and Distribution Lines	Circuit Miles of 765 kV Lines
AEP System (a)	216,306 (b)	2,026
APCo	51,147	644
CSPCo (a)	14,030	—
I&M	21,980	615
Kingsport Power Company	1,343	—
KPCo	10,780	258
OPCo	30,627	509
PSO	21,100	—
SWEPCo	20,455	—
TCC	29,571	—
TNC	13,578	—
Wheeling Power Company	1,696	—

(a) Includes 766 miles of 345 kV jointly owned lines.

(b) Includes 73 miles of transmission lines not identified with an operating company.

TITLES

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

Substantially all the fixed physical properties and franchises of TNC, APCo, PSO, and SWEPCo, except for limited exceptions, are subject to the lien of the mortgage and deed of trust securing the first mortgage bonds of each such company.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

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

CONSTRUCTION PROGRAM

GENERAL

With input from its state utility commissions, the AEP System continuously assesses the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. Thus, System reinforcement plans are subject to change, particularly with the restructuring of the electric utility industry. AEP forecasts $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.

PROPOSED TRANSMISSION FACILITIES

APCo is proceeding with its plan to build the Jacksons Ferry-Wyoming 765,000-volt transmission line. The WVPSC and the VSCC have issued certificates authorizing construction and operation of the line. On December 31, 2002, the U.S. Forest Service issued a final environmental impact statement and record of decision to allow the use of federal lands in the Jefferson National Forest for construction of a portion of the line. On May 11, 2004, the decision of the Forest Service was challenged by the Sierra Club in the United States District Court for the Western District of Virginia. APCo has intervened in that litigation. Construction of the line is underway and the project is scheduled to be completed by June 2006.

PROPOSED GENERATION FACILITY

In conjunction with an environmental impact study issued in August 2004, in the third quarter of 2004 we announced plans to construct a synthetic-gas-fired plant or plants of approximately 1,000 MW of capacity in the next five to six years utilizing integrated gasification combined cycle (IGCC) technology. We estimate that this new plant or plants will cost up to $1.7 billion. We have not determined a location for the plant or plants, but it or they will likely be in one of our eastern states, because of ready access to coal. 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. We have filed with PJM for transmission analysis of sites in Ohio, West Virginia and Kentucky.

Our significant planned environmental investments in emission control installations at existing coal-fired plants and our commitment to IGCC technology reinforce our belief that coal will be a lower-emission domestic energy source of the future and further signals our commitment to investing in clean, environmentally safe technology. For additional information regarding anticipated environmental expenditures, see *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *The Current Air Quality Regulatory Framework.*

CONSTRUCTION EXPENDITURES

The following table shows construction expenditures (including environmental expenditures) during 2002, 2003 and 2004 and current estimates of 2005 construction expenditures, in each case including AFUDC, but excluding assets acquired under leases.

	2002 Actual	2003 Actual	2004 Actual	2005 Estimate
		(in thousands)		
AEP System (a)	$1,709,800	$1,358,400	$1,693,200	2,732,400
AEGCo	5,300	22,200	15,800	19,900
APCo	276,500	288,800	452,200	696,700
CSPCo	136,800	136,300	149,800	193,900
I&M	159,400	184,600	176,800	322,800
KPCo	178,700	81,700	38,500	56,100
OPCo	354,800	249,700	345,500	765,600
PSO	89,400	86,800	82,300	126,200
SWEPCo	111,800	121,100	103,100	200,900
TCC	151,600	141,800	121,300	208,500
TNC	43,600	46,700	36,400	73,900

(a) Includes expenditures of other subsidiaries not shown. Amounts in 2002 and 2003 include construction expenditures related to entities classified in 2004 as discontinued operations. These amounts were $186,500,000 and $24,900,000, respectively. The figures reflect construction expenditures, not investments in subsidiary companies.

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

See Note 7 to the consolidated financial statements entitled *Commitments and Contingencies,* incorporated by reference in Item 8, for further information with respect to the construction plans of AEP and its operating subsidiaries for the next year.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could have a material adverse effect on results of operations and the financial condition of AEP, I&M, TCC and other AEP System companies. See Note 7 to the consolidated financial statements entitled *Commitments and Contingencies,* incorporated by reference in Item 8, for information with respect to nuclear incident liability insurance.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies,* incorporated by reference in Item 8.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

AEP, APCo, I&M, OPCo, SWEPCo and TCC. None.

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(c).

EXECUTIVE OFFICERS OF THE REGISTRANTS

AEP. The following persons are, or may be deemed, executive officers of AEP. Their ages are given as of March 1, 2005.

Name	Age	Office (a)
Michael G. Morris	58	Chairman of the Board, President and Chief Executive Officer of AEP and of AEPSC
Coulter R. Boyle III	56	Senior Vice President of AEP and Senior Vice President-Commercial Operations of AEPSC
Carl L. English	58	President-Utility Group of AEP and of AEPSC
Thomas M. Hagan	60	Executive Vice President-AEP Utilities-West of AEPSC
John B. Keane	58	Senior Vice President, General Counsel and Secretary of AEP and of AEPSC
Holly K. Koeppel	46	Executive Vice President-AEP Utilities-East of AEPSC
Robert P. Powers	51	Executive Vice President of AEP and Executive Vice President-Generation of AEPSC
Susan Tomasky	51	Executive Vice President and Chief Financial Officer of AEP and of AEPSC

(a) Before joining AEPSC in his current position in January 2004, Mr. Morris was Chairman of the Board, President and Chief Executive Officer of Northeast Utilities (1997-2003). Messrs. Boyle and Powers and Ms. Tomasky have been employed by AEPSC or System companies in various capacities (AEP, as such, has no employees) for the past five years. Before joining AEPSC in June 2000 as Senior Vice President-Governmental Affairs, Mr. Hagan was Senior Vice President-External Affairs of CSW (1996-2000). Before joining AEPSC in July 2000 as Vice President-New Ventures, Ms. Koeppel was Regional Vice President of Asia-Pacific Operations for Consolidated Natural Gas International (1996-2000). Messrs. Hagan and Powers, Ms. Koeppel and Ms. Tomasky became executive officers of AEP effective with their promotions to Executive Vice President on September 9, 2002, October 24, 2001, November 18, 2002 and January 26, 2000, respectively. As a result of AEP's realignment of its executive management team in July 2004, Messrs. Boyle and Keane became executive officers of AEP. Before joining AEPSC in his current position in July 2004, Mr. Keane was President of Bainbridge Crossing Advisors. Before that, he was Vice President-Administration for Northeast Utilities (1998-2002). Mr. English joined AEP as President-Utility Group and became an executive officer of AEP on August 1, 2004. Before joining AEPSC in his current position in August 2004, Mr. English was President and Chief Executive Officer of Consumers Energy gas division (1999-2004). All of the above officers are appointed annually for a one-year term by the board of directors of AEP, the board of directors of AEPSC, or both, as the case may be.

APCo, I&M, OPCo, SWEPCo and TCC. The names of the executive officers of APCo, I&M, OPCo, SWEPCo and TCC, the positions they hold with these companies, their ages as of March 1, 2005, and a brief account of their business experience during the past five years appear below. The directors and executive officers of APCo, I&M, OPCo, SWEPCo and TCC are elected annually to serve a one-year term.

Name	Age	Position	Period
Michael G. Morris (a)(b)	58	Chairman of the Board, President, Chief Executive Officer and Director of AEP	2004-Present
		Chairman of the Board, Chief Executive Officer and Director of AEPSC, APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		Chairman of the Board, President and Chief Executive Officer of Northeast Utilities	1997-2003
Coulter R. Boyle III	56	Senior Vice President of AEP and Senior Vice President-Commercial Operations and Director of AEPSC	2004-Present
		Vice President of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		Senior Vice President of AEPSC	2003-2004
		Vice President of AEPSC	1999-2003
Carl L. English (c)	58	President-Utility Group of AEP and President-Utility Group and Director of AEPSC	2004-Present
		Director and Vice President of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		President and Chief Executive Officer of Consumers Energy gas division	1999-2004
Thomas M. Hagan (d)	60	Executive Vice President-AEP Utilities-West and Director of AEPSC	2004-Present

Name	Age	Position	Period
		Vice Chairman of the Board, Vice President and Director of TCC and SWEPCo	2004-Present
		Vice President and Director of APCo, I&M and OPCo	2002-2004
		Executive Vice President of AEP	2004
		Executive Vice President-Shared Services of AEPSC	2002-2004
		Senior Vice President-Governmental Affairs of AEPSC	2000-2002
		Senior Vice President-External Affairs of CSW	1996-2000
John B. Keane (a)	58	Senior Vice President, General Counsel and Secretary of AEP and of AEPSC	2004-Present
		President of Bainbridge Crossing Advisors	2003-2004
		Vice President-Administration-Northeast Utilities	1998-2002
Holly K. Koeppel (e)	46	Executive Vice President-AEP Utilities-East and Director of AEPSC	2004-Present
		Vice Chairman of the Board, Vice President and Director of APCo, I&M and OPCo	2004-Present
		Executive Vice President of AEP	2004
		Executive Vice President-Commercial Operations of AEPSC	2002-2004
		Vice President-New Ventures	2000-2002
		Regional Vice President of Asia-Pacific Operations for Consolidated Natural Gas International	1996-2000
Robert P. Powers (a)	51	Executive Vice President of AEP	2004-Present
		Director-AEPSC	2001-Present
		Executive Vice President-Generation of AEPSC	2003-2004
		Director and Vice President of APCo, OPCo, SWEPCo and TCC	2001-Present
		Director of I&M	2001-Present
		Vice President of I&M	1998-Present
		Executive Vice President-Nuclear Generation and Technical Services of AEPSC	2001-2003
		Senior Vice President-Nuclear Operations of AEPSC	2000-2001
		Senior Vice President-Nuclear Generation and Director of AEPSC	1998-2000
Susan Tomasky (a)	51	Executive Vice President and Chief Financial Officer of AEP and of AEPSC	2004-Present
		Chief Financial Officer of AEP	2001-2004
		Director of AEPSC	1998-Present
		Vice President and Director of APCo, I&M, OPCo, SWEPCo and TCC	2000-Present
		Executive Vice President-Policy, Finance and Strategic Planning of AEPSC	2001-2004
		Executive Vice President-Legal, Policy and Corporate Communications of AEPSC	2000-2001
		Senior Vice President and General Counsel of AEPSC	1998-2001

(a) Messrs. Keane, Morris and Powers and Ms. Tomasky are directors of AEGCo, CSPCo, KPCo, PSO and TNC.

(b) Mr. Morris is a director of Cincinnati Bell, Inc. and The Hartford Financial Services Group, Inc.

(c) Mr. English is a director of CSPCo, KPCo, PSO and TNC.

(d) Mr. Hagan is a director of AEGCo, PSO and TNC.

(e) Ms. Koeppel is a director of CSPCo and KPCo.

APCo:

Name	Age	Position	Period
Dana E. Waldo	53	President and Chief Operating Officer of APCo and Kingsport Power Company	2004-Present
		President and Chief Executive Officer of West Virginia Roundtable	1999-2004
		Vice President of APCo	1995-1999

I&M:

Name	Age	Position	Period
Marsha P. Ryan	54	President and Chief Operating Officer of I&M	2004-Present
		Senior Vice President-Customer Operations of AEPSC	2000-2004
		State President-Ohio	1996-2000
		Vice President of APCo, I&M, SWEPCo and TCC	2000-2004
		Vice President of CSPCo and OPCo	1996-2004

OPCo:

Name	Age	Position	Period
Kevin E. Walker	42	President and Chief Operating Officer of CSPCo, OPCo and WPCo	2004-Present
		Vice President of Consolidated Edison (New York)	2001-2004
		Vice President of Public Service of New Hampshire	2000-2001

SWEPCo:

Name	Age	Position	Period
Nicholas K. Akins	44	President and Chief Operating Officer of SWEPCo	2004-Present
		Vice President of AEPSC	2000-2004
		Director of CSW	1999-2000

TCC:

Name	Age	Position	Period
Charles R. Patton	45	President and Chief Operating Officer of TCC	2004-Present
		Vice President of Governmental and Environmental Affairs-Texas	2002-2004
		Vice President of State Governmental Affairs of AEPSC	2000-2002
		Director of Government Affairs	1999-2000

PART II

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

AEP. The information required by this item is incorporated herein by reference to the material under *Common Stock and Dividend Information* in the 2004 Annual Report.

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The common stock of these companies is held solely by AEP. The amounts of cash dividends on common stock paid by these companies to AEP during 2004 and 2003 are incorporated by reference to the material under *Statement of Retained Earnings* in the 2004 Annual Reports.

ITEM 6. SELECTED FINANCIAL DATA

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(a).

AEP, APCo, I&M, OPCo, SWEPCo and TCC. The information required by this item is incorporated herein by reference to the material under *Selected Consolidated Financial Data* in the 2004 Annual Reports.

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

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis* in the 2004 Annual Reports.

AEP, APCo, I&M, OPCo, SWEPCo and TCC. The information required by this item is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis* in the 2004 Annual Reports.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The information required by this item is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis* in the 2004 Annual Reports.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The information required by this item is incorporated herein by reference to the financial statements and financial statement schedules described under Item 15 herein.

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

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. None.

ITEM 9A. CONTROLS AND PROCEDURES

During 2004, management, including the principal executive officer and principal financial officer of AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo TCC and TNC (collectively, the "Registrants"), evaluated the Registrants' disclosure controls and procedures relating to the recording, processing, summarization and reporting of information in the Registrants' periodic reports filed with the SEC. These disclosure controls and procedures have been designed to ensure that (a) material information relating to the Registrants is made known to the Registrants' management, including these officers, by other employees of the Registrants and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. The Registrants' disclosure controls and procedures can only provide reasonable, not absolute, assurance that the above objectives have been met.

As of December 31, 2004, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

AEP's East zone public utility subsidiaries integrated into PJM on October 1, 2004. In connection with this integration, AEP and these subsidiaries implemented or modified a number of business processes and controls to facilitate participation in, and resultant settlement within, the PJM market. Apart from this, there have been no significant changes in AEP's internal controls over financial reporting (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) during the fourth quarter of 2004 that have materially affected, or are reasonably likely to materially affect, AEP's internal controls over financial reporting.

Additional information required by this item of AEP, as an accelerated filer, is incorporated by reference to *Management's Report on Internal Controls over Financial Reporting*, included in the 2004 Annual Reports.

ITEM 9B. OTHER INFORMATION

AEP's East zone public utility subsidiaries integrated into PJM on October 1, 2004 pursuant to various agreements filed herewith as exhibits. As a result, PJM has assumed functional control of the transmission grid of AEP's East zone public utility subsidiaries.

The Human Resources Committee of AEP's Board of Directors (the "Committee") has approved the performance metrics that will be used to determine the amount of the awards under AEP's Senior Officer Incentive Plan (the "SOIP") for 2005 for AEP's executive officers. The performance metrics are based on safety performance, workforce development, strategic planning, and environmental stewardship. The overall funding level for all of AEP's incentive plans, including the SOIP, will be based on the extent to which AEP's earnings per share improves over the prior year and meets or exceeds the 2005 budget approved by AEP's Board of Directors. However, this overall funding level may be reduced at the discretion of the CEO or adjusted, either positively or negatively, at the discretion of the Committee.

The Committee also set the 2005 annual incentive award targets, expressed as a percentage of salary, under the SOIP for AEP's executive officers. Payouts of annual incentive awards are dependent on the level of achievement of the corporate financial and operational goals approved by the Committee and discussed above. Target annual incentive awards were set at 100 percent of salary for the CEO, 65 percent of salary for the CFO, and either 50 or 60 percent of salary for the remaining executive officers of AEP.

Individual awards recommendations for executive officers, other than for Mr. Morris, are determined on a discretionary basis by Mr. Morris and are subject to the approval of the Committee. The individual award recommendation for Mr. Morris is determined on a discretionary basis by the Committee and is subject to the approval of the independent members of AEP's Board of Directors.

On January 25, 2005, the independent members of the AEP Board of Directors set the 2005 annual base salary for Michael G. Morris at $1,150,000. On January 25, 2005, the Committee set the 2005 annual base salaries for Susan Tomasky at $500,000; Thomas M. Hagan at $440,000; Holly K. Koeppel at $440,000; and Robert P. Powers at $450,000. Each of these individuals is an AEP named executive officer for 2004. For further information regarding executive compensation, see "Item 11. Executive Compensation" herein.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANTS

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Nominees for Director* and *Section 16(a) Beneficial Ownership Reporting Compliance* of the definitive proxy statement of AEP for the 2005 annual meeting of shareholders, to be filed within 120 days after December 31, 2004. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Election of Directors* of the definitive information statement of each company for the 2005 annual meeting of stockholders, to be filed within 120 days after December 31, 2004. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

I&M, SWEPCo and TCC. The names of the directors and executive officers of I&M, SWEPCo and TCC, the positions they hold with I&M, SWEPCo and TCC, their ages as of March 1, 2005, and a brief account of their business experience during the past five years appear below or under the caption *Executive Officers of the Registrants* in Part I of this report.

I&M:

Name	Age	Position	Period
K. G. Boyd	53	Director	1997-Present
		Vice President-Fort Wayne Region Distribution Operations	2000-Present
		Indiana Region Manager	1997-2000
John E. Ehler	48	Director	2001-Present
		Manager of Distribution Systems-Fort Wayne District	2000-Present
		Region Operations Manager	1997-2000
Patrick C. Hale	50	Director	2003-Present
		Plant Manager, Rockport Plant	2003-Present
		Energy Production Manager, Rockport Plant	2001-2003
		Energy Production Manager, Mountaineer Plant (APCo)	1997-2001
David L. Lahrman	53	Director and Manager, Region Support	2001-Present
		Fort Wayne District Manager	1997-2001
Marc E. Lewis	50	Director	2001-Present
		Assistant General Counsel of AEPSC	2001-Present
		Senior Counsel of AEPSC	2000-2001
		Senior Attorney of AEPSC	1994-2000
Susanne M. Moorman Rowe	55	Director and General Manager, Corporate Communications	2004-Present
		Director and General Manager, Community Services	2000-2004
		Manager, Customer Services Operations	1997-2000
Venita McCellon-Allen(a)	45	Director and Senior Vice President-Shared Services of AEPSC	2004-Present
		Director of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		Senior Vice President-Human Resources for Baylor Health Care System	2000-2004
		Senior Vice President-Customer Services and Corporate Development of CSW	1996-2000
John R. Sampson	52	Director and Vice President	1999-Present
		Indiana State President	2000-2004
		Indiana & Michigan State President	1999-2000
		Site Vice President, Cook Nuclear Plant	1998-1999

SWEPCo and TCC:

Name	Age	Position	Period
Venita McCellon-Allen (a)	45	Director and Senior Vice President-Shared Services of AEPSC	2004-Present
		Director of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		Senior Vice President-Human Resources for Baylor Health Care Systems	2000-2004
		Senior Vice President-Customer Services and Corporate Development of CSW	1996-2000
Stephen P. Smith (b)	44	Senior Vice President and Treasurer of AEP	2004-Present
		Senior Vice President-Corporate Accounting, Planning & Strategy, Treasurer and Director of AEPSC	2003-Present
		Treasurer of APCo, I&M, OPCo, SWEPCo and TCC	2003-Present
		Vice President and Director of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		President and Chief Operating Officer-Corporate Services for NiSource	1999-2003

(a) Ms. McCellon-Allen is a director of CSPCo, KPCo, PSO and TNC.

(b) Mr. Smith is a director of AEGCo, CSPCo, KPCo, PSO and TNC.

ITEM 11. EXECUTIVE COMPENSATION

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Directors Compensation and Stock Ownership Guidelines, Executive Compensation* and the performance graph of the definitive proxy statement of AEP for the 2005 annual meeting of shareholders to be filed within 120 days after December 31, 2004.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive information statement of each company for the 2005 annual meeting of stockholders, to be filed within 120 days after December 31, 2004.

I&M, SWEPCo and TCC. The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive information statement of APCo for the 2005 annual meeting of stockholders, to be filed within 120 days after December 31, 2004.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* of the definitive proxy statement of AEP for the 2005 annual meeting of shareholders to be filed within 120 days after December 31, 2004.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* in the definitive information statement of each company for the 2005 annual meeting of stockholders, to be filed within 120 days after December 31, 2004.

I&M. All 1,400,000 outstanding shares of Common Stock, no par value, of I&M are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of I&M generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2005, by each director and nominee of I&M and each of the executive officers of I&M named in the summary compensation table, and by all directors and executive officers of I&M as a group. It is based on information provided to I&M by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of I&M. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares (a)		Stock Units (b)	Total
Karl G. Boyd	12,805		253	13,058
John E. Ehler	—		—	—
Carl L. English	—		30,632	30,632
Patrick C. Hale	3,342		—	3,342
Holly K. Koeppel	61,612		380	61,992
David L. Lahrman	276		—	276
Marc E. Lewis	9,859		—	9,859
Venita McCellon-Allen	—		10,103	10,103
Suzanne M. Moorman Rowe	42		—	42
Michael G. Morris	360,587	(e)	—	360,587
Robert P. Powers	200,957	(c)	1,345	202,302
Marsha P. Ryan	32,565		1,047	33,612
John R. Sampson	18,634		—	18,634
Susan Tomasky	240,334	(c)	6,744	247,078
All Directors and Executive Officers	1,026,244	(c)(d)	50,504	1,076,748

Name	AEP Retirement Savings Plan (Share Equivalents)
Karl G. Boyd	100
John E. Ehler	—
Carl L. English	—
Patrick C. Hale	76
Holly K. Koeppel	246
David L. Lahrman	276
Marc E. Lewis	1,410
Venita McCellon-Allen	—
Marsha P. Ryan	6,189
Suzanne M. Moorman Rowe	42
Michael G. Morris	—
Robert P. Powers	658
John R. Sampson	934
Susan Tomasky	2,668
All Directors and Executive Officers	12,598

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan. Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Boyd, 12,700; Mr. Hale, 3,266; Ms. Koeppel, 61,366; Mr. Lewis, 8,449; Mr. Powers, 200,299; Ms. Ryan, 26,366; Mr. Sampson, 17,700; and Ms. Tomasky, 237,666.

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed.
(b) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.
(c) 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.
(d) Represents less than 1.5% of the total number of shares outstanding.
(e) Consists of restricted shares with different vesting schedules and accrued dividends.

SWEPCo. All 7,536,640 outstanding shares of Common Stock, $18 par value, of SWEPCo are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of SWEPCo generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2005, by each director and nominee of SWEPCo and each of the executive officers of SWEPCo named in the summary compensation table, and by all directors and executive officers of SWEPCo as a group. It is based on information provided to SWEPCo by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of SWEPCo. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares (a)		Stock Units (b)	Total
Nicholas K. Akins	13,877		—	13,877
Carl L. English	—		30,632	30,632
Thomas M. Hagan	144,529		155	144,684
John B. Keane	—		15,316	15,316
Holly K. Koeppel	61,612		380	61,992
Venita McCellon-Allen	—		10,103	10,103
Michael G. Morris	360,587	(e)	—	360,587
Robert P. Powers	200,957	(c)	1,345	202,302
Stephen P. Smith	16,500		—	16,500
Susan Tomasky	240,334	(c)	6,744	247,078
All Directors and Executive Officers	1,123, 627	(c)(d)	64,675	1,188,302

Name	AEP Retirement Savings Plan (Share Equivalents)
Nicholas K. Akins	1,177
Carl L. English	—
Thomas M. Hagan	4,537
John B. Keane	—
Holly K. Koeppel	246
Venita McCellon-Allen	—
Michael G. Morris	—
Robert P. Powers	658
Stephen P. Smith	—
Susan Tomasky	2,668
All Directors and Executive Officers	9,286

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan. Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Akins, 12,700; Mr. Hagan, 129,499; Ms. Koeppel, 61,367; Mr. Morris, 49,666; Mr. Powers, 200,299; Mr. Smith, 16,500; and Ms. Tomasky, 237,666.

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed.
(b) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.
(c) 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.
(d) Represents less than 1.5% of the total number of shares outstanding.
(e) Consists of restricted shares with different vesting schedules and accrued dividends.

TCC. All 2,211,678 outstanding shares of Common Stock, $25 par value, of TCC are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of TCC generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2005, by each director and nominee of TCC and each of the executive officers of TCC named in the summary compensation table, and by all directors and executive officers of TCC as a group. It is based on information provided to TCC by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of TCC. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares (a)		Stock Units (b)	Total
Carl L. English	30,632		—	30,632
Thomas M. Hagan	144,529		155	144,684
John B. Keane	—		15,316	15,316
Holly K. Koeppel	61,612		380	61,992
Venita McCellon-Allen	—		10,103	10,103
Michael G. Morris	360,587	(e)	—	360,587
Charles R. Patton	7,400		—	7,400
Robert P. Powers	200,957	(c)	1,345	202,302
Stephen P. Smith	16,500		—	16,500
Susan Tomasky	240,334	(c)	6,744	247,078
All Directors and Executive Officers	1,147,782	(c)(d)	34,043	1,181,825

Name	AEP Retirement Savings Plan (Share Equivalents)
Carl L. English	—
Thomas M. Hagan	4,537
John B. Keane	—
Holly K. Koeppel	246
Venita McCellon-Allen	—
Michael G. Morris	—
Charles R. Patton	—
Robert P. Powers	658
Stephen P. Smith	—
Susan Tomasky	2,668
All Directors and Executive Officers	8,109

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan. Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Hagan, 129,499; Ms. Koeppel, 61,367; Mr. Morris, 49,666; Mr. Patton, 7,400; Mr. Powers, 200,299; Mr. Smith, 16,500; and Ms. Tomasky, 237,666.

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed.
(b) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.
(c) 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.
(d) Represents less than 1.5% of the total number of shares outstanding.
(e) Consists of restricted shares with different vesting schedules and accrued dividends.

EQUITY COMPENSATION PLAN INFORMATION

Information required by this item is incorporated by reference from the discussion under the heading *Equity Compensation Plan Information* in our proxy statement for the 2005 Annual Meeting of Shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC: None.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP. The information required by this item is incorporated herein by reference to the definitive proxy statement of AEP for the 2005 annual meeting of shareholders to be filed within 120 days after December 31, 2004.

APCo and OPCo. The information required by this item is incorporated herein by reference to the definitive information statement of each company for the 2005 annual meeting of stockholders, to be filed within 120 days after December 31, 2004.

AEGCo, CSPCo, I&M, KPCo, PSO, SWEPCo, TCC and TNC.

Each of the above is wholly-owned subsidiaries of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement of AEP for the 2005 annual meeting of shareholders to be filed within 120 days after December 31, 2004. The following table presents directly billed fees for professional services rendered by Deloitte & Touche LLP for the audit of these companies' annual financial statements for the years ended December 31, 2003 and 2004, and fees directly billed for other services rendered by Deloitte & Touche LLP during those periods. Deloitte & Touche LLP also provides additional professional and other services to the AEP System, the cost of which may ultimately be allocated to these companies though not billed directly to them. For a description of these fees and services, see the definitive proxy statement of AEP for the 2005 annual meeting of shareholders to be filed within 120 days after December 31, 2004.

	AEGCo		CSPCo		I&M	
	2004	2003	2004	2003	2004	2003
Audit Fees						
Financial Statement Audits	$164,303		$608,935		$679,061	
Sarbanes-Oxley 404	112,341		518,610		490,537	
Audit Fees – Other	19,530		57,660		49,290	
Audit Fees Subtotal	296,174	$136,100	1,185,205	$385,000	1,218,888	$366,900
Audit-Related Fees	0	0	5,000	0	184,000	0
Tax Fees	67,539	1,000	888,188	349,000	1,136,796	26,000
TOTAL	$363,713	$137,100	$2,078,393	$734,000	$2,539,684	$392,900

	KPCo		PSO		SWEPCo	
	2004	2003	2004	2003	2004	2003
Audit Fees						
Financial Statement Audits	$413,013		$357,053		$411,970	
Sarbanes-Oxley 404	284,581		273,793		318,007	
Audit Fees – Other	36,270		24,180		27,900	
Audit Fees Subtotal	733,864	$289,000	655,026	$187,300	757,877	$212,900
Audit-Related Fees	0	0			10,000	0
Tax Fees	81,412	8,000	438,845	35,000	567,665	89,000
TOTAL	$815,276	$297,000	$1,093,871	$222,300	$1,335,542	$301,900

	TCC		TNC	
	2004	2003	2004	2003
Audit Fees				
Financial Statement Audits	$446,899		$159,950	
Sarbanes-Oxley 404	357,257		188,080	
Audit Fees – Other	46,500		26,040	
Audit Fees Subtotal	850,656	$511,000	374,070	$188,900
Audit-Related Fees	21,500		8,325	
Tax Fees	896,577	89,000	235,477	54,000
TOTAL	$1,768,733	$600,000	$617,872	$242,900

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

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

	Page
1. FINANCIAL STATEMENTS:	
The following financial statements have been incorporated herein by reference pursuant to Item 8.	
AEGCo:	
Statements of Income for the years ended December 31, 2004, 2003 and 2002; Statements of Retained Earnings for the years ended December 31, 2004, 2003 and 2002; Balance Sheets as of December 31, 2004 and 2003; Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Schedule of Long-term Debt as of December 31, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
AEP and Subsidiary Companies:	
Reports of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Operations for the years ended December 31, 2004, 2003 and 2002; Consolidated Balance Sheets as of December 31, 2004 and 2003; Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Consolidated Statements of Common Shareholders' Equity and Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002; Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries at December 31, 2004 and 2003; Schedule of Consolidated Long-term Debt of Subsidiaries at December 31, 2004 and 2003; Notes to Consolidated Financial Statements.	

	Page
APCo, I&M, SWEPCo and TCC:	
Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002; Consolidated Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002; Consolidated Balance Sheets as of December 31, 2004 and 2003; Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Schedule of Preferred Stock as of December 31, 2004 and 2003; Schedule of Long-term Debt as of December 31, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
CSPCo:	
Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002; Consolidated Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002; Consolidated Balance Sheets as of December 31, 2004 and 2003; Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Schedule of Long-term Debt as of December 31, 2004 and 2003; notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
KPCo:	
Statements of Income for the years ended December 31, 2004, 2003 and 2002; Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002; Balance Sheets as of December 31, 2004 and 2003; Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Schedule of Long-term Debt as of December 31, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
PSO and TNC:	
Statements of Income (or Statements of Operations) for the years ended December 31, 2004, 2003 and 2002; Statements of Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002; Balance Sheets as of December 31, 2004 and 2003; Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Schedules of Preferred Stock as of December 31, 2004 and 2003; Schedule of Long-term Debt as of December 31, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
2. FINANCIAL STATEMENT SCHEDULES:	
Financial Statement Schedules are listed in the Index to Financial Statement Schedules (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Report of Independent Registered Public Accounting Firm	S-1
3. EXHIBITS:	
Exhibits for AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference	E-1

SIGNATURES

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

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Executive Vice President and Chief Financial Officer)

Date: March 1, 2005

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

Signature	Title	Date
(i) Principal Executive Officer:		
*MICHAEL G. MORRIS	Chairman of the Board, President, Chief Executive Officer And Director	March 1, 2005
(ii) Principal Financial Officer:		
/s/ SUSAN TOMASKY **(Susan Tomasky)**	Executive Vice President and Chief Financial Officer	March 1, 2005
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Senior Vice President, Controller and Chief Accounting Officer	March 1, 2005
(iv) A Majority of the Directors:		
*E. R. BROOKS *DONALD M. CARLTON *JOHN P. DESBARRES *ROBERT W. FRI *WILLIAM R. HOWELL *LESTER A. HUDSON, JR. *LEONARD J. KUJAWA *LIONEL L. NOWELL, III *RICHARD L. SANDOR *DONALD G. SMITH *KATHRYN D. SULLIVAN		
*By: /s/ SUSAN TOMASKY **(Susan Tomasky, Attorney-in-Fact)**		March 1, 2005

SIGNATURES

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

AEP GENERATING COMPANY

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Vice President and Chief Financial Officer)

Date: March 1, 2005

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

Signature	Title	Date
(i) **Principal Executive Officer:**		
*MICHAEL G. MORRIS	Chairman of the Board, Chief Executive Officer and Director	March 1, 2005
(ii) **Principal Financial Officer:**		
/s/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	March 1, 2005
(iii) **Principal Accounting Officer:**		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 1, 2005
(iv) **A Majority of the Directors:**		
* THOMAS M. HAGAN * JOHN B. KEANE *ROBERT P. POWERS *STEPHEN P. SMITH		
*By: /s/ SUSAN TOMASKY **(Susan Tomasky, Attorney-in-Fact)**		March 1, 2005

SIGNATURES

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

AEP TEXAS CENTRAL COMPANY
AEP TEXAS NORTH COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Vice President and Chief Financial Officer)

Date: March 1, 2005

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

Signature	Title	Date
(i) Principal Executive Officer:		
*MICHAEL G. MORRIS	Chairman of the Board, Chief Executive Officer and Director	March 1, 2005
(ii) Principal Financial Officer:		
/s/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	March 1, 2005
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 1, 2005
(iv) A Majority of the Directors:		
*CARL L. ENGLISH *THOMAS M. HAGAN *JOHN B. KEANE *VENITA MCCELLON-ALLEN *ROBERT P. POWERS *STEPHEN P. SMITH		

*By: /s/ SUSAN TOMASKY
(Susan Tomasky, Attorney-in-Fact)
March 1, 2005

SIGNATURES

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

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
KENTUCKY POWER COMPANY
OHIO POWER COMPANY

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Vice President and Chief Financial Officer)

Date: March 1, 2005

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

Signature	Title	Date
(i) Principal Executive Officer:		
*MICHAEL G. MORRIS	Chairman of the Board, Chief Executive Officer and Director	March 1, 2005
(ii) Principal Financial Officer:		
/s/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	March 1, 2005
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 1, 2005
(iv) A Majority of the Directors:		
*CARL L. ENGLISH *JOHN B. KEANE *HOLLY K. KOEPPEL *VENITA MCCELLON-ALLEN *ROBERT P. POWERS *STEPHEN P. SMITH		
*By: /s/ SUSAN TOMASKY **(Susan Tomasky, Attorney-in-Fact)**		March 1, 2005

SIGNATURES

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

INDIANA MICHIGAN POWER COMPANY

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Vice President
and Chief Financial Officer)

Date: March 1, 2005

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

Signature	Title	Date
(i) Principal Executive Officer:		
*MICHAEL G. MORRIS	Chairman of the Board, Chief Executive Officer and Director	March 1, 2005
(ii) Principal Financial Officer:		
/s/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	March 1, 2005
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 1, 2005
(iv) A Majority of the Directors:		
*K. G. BOYD *JOHN E. EHLER *CARL L. ENGLISH *PATRICK C. HALE *HOLLY KELLER KOEPPEL *DAVID L. LAHRMAN *MARC E. LEWIS *VENITA MCCELLON-ALLEN *SUSANNE M. MOORMAN ROWE *ROBERT P. POWERS *JOHN R. SAMPSON		
*By: /s/ SUSAN TOMASKY **(Susan Tomasky, Attorney-in-Fact)**		March 1, 2005

INDEX TO FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the consolidated financial statements of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2004 and 2003, and for each of the three years in the period ended December 31, 2004, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, and have issued our reports thereon dated February 28, 2005 (which reports express unqualified opinions and include an explanatory paragraph concerning the adoption of new accounting pronouncements in 2002, 2003 and 2004); such financial statements and reports are included in your 2004 Annual Report and are incorporated herein by reference. Our audits also included the financial statement schedule of the Company listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the corresponding basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche, LLP

Columbus, Ohio
February 28, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the financial statements of the AEP Texas Central Company and subsidiary, AEP Texas North Company, Appalachian Power Company and subsidiaries, Columbus Southern Power Company and subsidiaries, Indiana Michigan Power Company and subsidiaries, Kentucky Power Company, Ohio Power Company Consolidated, Public Service Company of Oklahoma and Southwestern Electric Power Company Consolidated (collectively, the "Companies") as of December 31, 2004 and 2003, and for each of the three years in the period ended December 31, 2004, and have issued our reports thereon dated February 28, 2005 (which reports express unqualified opinions and include an explanatory paragraph concerning the adoption of new accounting pronouncements in 2002, 2003 and 2004); such financial statements and reports are included in your 2004 Annual Reports and are incorporated herein by reference. Our audits also included the financial statement schedules of the Companies listed in Item 15. These financial statement schedules are the responsibility of the Companies' management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche, LLP

Columbus, Ohio
February 28, 2005

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 123,685	$ 39,766	$ 7,989	$ 94,265	$ 77,175
Year Ended December 31, 2003	107,578	55,087	7,234	46,214	123,685
Year Ended December 31, 2002	68,429	87,044	11,767	59,662	107,578

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 1,710	$ 3,493	$ -	$ 1,710	$ 3,493
Year Ended December 31, 2003	346	1,712	-	348	1,710
Year Ended December 31, 2002	186	162	1	3	346

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

AEP TEXAS NORTH COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 175	$ 787	$ -	$ 175	$ 787
Year Ended December 31, 2003	5,041	123	-	4,989	175
Year Ended December 31, 2002	196	4,846	17	18	5,041

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 2,085	$ 3,059	$ 4,201	$ 3,784	$ 5,561
Year Ended December 31, 2003	13,439	4,708	433	16,495	2,085
Year Ended December 31, 2002	1,877	3,937	12,367	4,742	13,439

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 531	$ 577	$ 187	$ 621	$ 674
Year Ended December 31, 2003	634	96	-	199	531
Year Ended December 31, 2002	745	(100)	-	11	634

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 531	$ 195	$ 90	$ 629	$ 187
Year Ended December 31, 2003	578	37	-	84	531
Year Ended December 31, 2002	741	(161)	-	2	578

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

KENTUCKY POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 736	$ 43	$ 27	$ 772	$ 34
Year Ended December 31, 2003	192	8	912	376	736
Year Ended December 31, 2002	264	(68)	-	4	192

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

OHIO POWER COMPANY CONSOLIDATED
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 789	$ 122	$ 89	$ 907	$ 93
Year Ended December 31, 2003	909	42	18	180	789
Year Ended December 31, 2002	1,379	(457)	-	13	909

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 37	$ 21	$ 55	$ 37	$ 76
Year Ended December 31, 2003	84	37	-	84	37
Year Ended December 31, 2002	44	7	33	-	84

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 2,093	$ (2,079)	$ 134	$ 103	$ 45
Year Ended December 31, 2003	2,128	103	-	138	2,093
Year Ended December 31, 2002	89	2,036	4	1	2,128

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

EXHIBIT INDEX

The documents listed below are being filed or have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof. Exhibits ("Ex") not identified as previously filed are filed herewith. Exhibits, designated with a dagger (†), are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form pursuant to Item 14(c) of this report.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
REGISTRANT: AEGCo	**File No. 0-18135**	
3(a)	Articles of Incorporation of AEGCo.	Registration Statement on Form 10 for the Common Shares of AEGCo, Ex 3(a).
3(b)	Copy of the Code of Regulations of AEGCo, amended as of June 15, 2000.	2000 Form 10-K, Ex 3(b).
10(a)	Capital Funds Agreement dated as of December 30, 1988 between AEGCo and AEP.	Registration Statement No. 33-32752, Ex 28(a).
10(b)(1)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B).
10(b)(2)	Unit Power Agreement, dated as of August 1, 1984, among AEGCo, I&M and KPCo.	Registration Statement No. 33-32752, Ex 28(b)(2).
10(c)	Lease Agreements, dated as of December 1, 1989, between AEGCo and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C); 1993 Form 10-K, Ex 10(c)(1-6)(B).
*13	Copy of those portions of the AEGCo 2004 Annual Report, which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: AEP‡	**File No. 1-3525**	
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated January 13, 1999.	1998 Form 10-K, Ex 3(c).
3(b)	By-Laws of AEP, as amended through December 15, 2003	2003 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.	Registration Statement No. 333-86050, Ex 4(a)(b)(c); Registration Statement No. 333-105532, Ex 4(d)(e)(f).
4(b)	Forward Purchase Contract Agreement, dated as of June 11, 2002, between AEP and The Bank of New York, as Forward Purchase Contract Agent	2002 Form 10-K, Ex 4(c).
10(a)	Interconnection Agreement, dated July 6, 1951,	Registration Statement No. 2-52910, Ex 5(a);

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-61009, Ex 5(b); 1990 Form 10-K, Ex 10(a)(3).
10(b)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K; Ex 10(b) 1988 Form 10-K, Ex 10(b)(2).
10(d)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(d).
*10(e)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(e)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(e)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(f)	Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C); Registration Statement No. 33-32753, Ex 28(a)(1-6)(C); AEGCO 1993 Form 10-K, Ex 10(c)(1-6)(B); I&M 1993 Form 10-K, Ex 10(e)(1-6)(B).
10(g)	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested)	OPCo 1994 Form 10-K, Ex 10(l)(2).
10(h)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l)
10(i)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, by and among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation	1997 Form 10-K, Ex 10(f).
10(i)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger	Form 8-K, Ex 10, dated December 15, 1999.
†10(j)	AEP Accident Coverage Insurance Plan for directors.	1985 Form 10-K, Ex 10(g)
*†10(k)(1)	AEP Deferred Compensation and Stock Plan for Non-Employee Directors, as amended December 10, 2003.	2003 Form 10-K, Ex 10(k)(1)
†10(k)(2)	AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended December 10, 2003.	2003 Form 10-K, Ex 10(k)(2).
†10(l)(1)(A)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.	2000 Form 10-K, Ex 10(j)(1)(A)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(l)(1)(B)	Guaranty by AEP of AEPSC Excess Benefits Plan.	1990 Form 10-K, Ex 10(h)(1)(B)
†10(l)(1)(C)	First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.	2002 Form 10-K; Ex 10(1)(1)(c)
†10(l)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of September 1, 2004 (Non-Qualified).	2003 Form 10-K, Ex 10(l)(2). Form 8-K, Ex 99.1, dated September 1, 2004,
†10(l)(3)	Service Corporation Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3).
†10(m)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(m)(1).
†10(m)(2)	Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.	2000 Form 10-K, Ex 10(s)
†10(m)(3)	Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel.	2002 Form 10-K; Ex 10(m)(3)(A)
†10(m)(4)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K; Ex 10(m)(4)
†10(m)(5)	Letter Agreement dated June 4, 2004 between AEPSC and Carl English	Form 10-Q, Ex 10(b), September 30, 2004
†10(n)	AEP System Senior Officer Annual Incentive Compensation Plan.	1996 Form 10-K, Ex 10(i)(1)
†10(o)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998
†10(o)(2)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K; Ex 10(o)(2)
†10(p)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2003.	2003 Form 10-K, Ex 10(q)(1).
†10(q)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(r)
†10(r)	Nuclear Key Contributor Retention Plan dated May 1, 2000.	2002 Form 10-K; Ex 10(s)
†10(s)	AEP Change In Control Agreement effective January 1, 2005.	Form 8-K, Ex 10.1, dated January 10, 2005
†10(t)(1)	AEP System 2000 Long-Term Incentive Plan, as amended December 10, 2003.	2003 Form 10-K, Ex 10(u).
†10(t)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System 2000 Long-Term Incentive Plan, as amended	Form 10-Q, Ex. 10(c), September 30, 2004
†10(u)(1)	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.	CSW 1998 Form 10-K, Ex 18, File No. 1-1443,
†10(u)(2)	Certified AEP Utilities, Inc. (formerly CSW) Board Resolutions of July 16, 1996.	2003 Form 10-K, Ex 10(v)(3).
†10(u)(3)	Central and South West Corporation Executive Deferred Savings Plan as amended and restated effective as of January 1, 1997.	CSW 1998 Form 10-K, Ex 24, File No. 1-1443.
*†10(v)	Schedule of Non-Employee Directors' Annual Compensation	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*†10(w)	Base Salaries for Named Executive Officers	
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the AEP 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
*21	List of subsidiaries of AEP.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT:	**APCo‡ File No. 1-3457**	
3(a)	Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.	1996 Form 10-K, Ex 3(d).
3(b)	By-Laws of APCo, amended as of October 24, 2001.	2001 Form 10-K, Ex 3(e).
4(a)	Mortgage and Deed of Trust, dated as of December 1, 1940, between APCo and Bankers Trust Company and R. Gregory Page, as Trustees, as amended and supplemented.	Registration Statement No. 2-7289, Ex 7(b); Registration Statement No. 2-19884, Ex 2(1) Registration Statement No. 2-24453, Ex 2(n); Registration Statement No. 2-60015, Ex 2(b)(2-10)(12)(14-28); Registration Statement No. 2-64102, Ex 2(b)(29); Registration Statement No. 2-66457, Ex (2)(b)(30-31); Registration Statement No. 2-69217, Ex 2(b)(32); Registration Statement No. 2-86237, Ex 4(b); Registration Statement No. 33-11723, Ex 4(b); Registration Statement No. 33-17003, Ex 4(a)(ii), Registration Statement No. 33-30964, Ex 4(b); Registration Statement No. 33-40720, Ex 4(b); Registration Statement No. 33-45219, Ex 4(b); Registration Statement No. 33-46128, Ex 4(b)(c); Registration Statement No. 33-53410, Ex 4(b); Registration Statement No. 33-59834, Ex 4(b); Registration Statement No. 33-50229, Ex 4(b)(c); Registration Statement No. 33-58431, Ex 4(b)(c)(d)(e); Registration Statement No. 333-01049, Ex 4(b)(c); Registration Statement No. 333-20305, Ex 4(b)(c); 1996 Form 10-K, Ex 4(b); 1998 Form 10-K, Ex 4(b).
4(b)	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of	Registration Statement No. 333-45927, Ex 4(a); Registration Statement No. 333-49071, Ex 4(b);

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	New York, As Trustee.	Registration Statement No. 333-84061, Ex 4(b)(c); 1999 Form 10-K, Ex 4(c); Registration Statement No. 333-81402, Ex 4(b)(c)(d); Registration Statement No. 333-100451, Ex 4(b); 2002 Form 10-K, Ex 4(c).
4(c)	Company Order and Officer's Certificate to The Bank of New York, dated July 1, 2004, establishing terms of Floating Rate Notes, Series C, due 2007.	Form 8-K, Ex 4(a), dated July 1, 2004.
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); 1989 Form 10-K, Ex 10(a)(1)(F); 1992 Form 10-K, Ex 10(a)(1)(B)].
10(a)(2)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); 1992 Form 10-K, Ex 10(a)(2)(B).
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e).
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, File No. 1-3525, Ex 10(a)(3).
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	AEP 1985 Form 10-K, Ex 10(b); AEP 1988 Form 10-K, Ex 10(b)(2).
*10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525.
10(f)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation.	AEP 1997 Form 10-K, Ex 10(f), File No. 1-3525.
10(f)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger.	Form 8-K, Ex 10, dated December 15, 1999.
†10(g)	AEP System Senior Officer Annual Incentive Compensation Plan	AEP 1996 Form 10-K, Ex 10(i)(1), File No. 1-3525.
†10(h)(1)(A)	AEP System Excess Benefit Plan, Amended and	AEP 2000 Form 10-K, Ex 10(j)(1)(A), File No. 1-3525.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Restated as of January 1, 2001.	
†10(h)(1)(B)	First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.	2002 Form 10-K; Ex 10(h)(1)(B).
†10(h)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of September 1, 2004 (Non-Qualified).	AEP Form 8-K, Ex 99.1, dated September 1, 2004
†10(h)(3)	Umbrella Trust for Executives.	AEP 1993 Form 10-K, Ex 10(g)(3), File No. 1-3525.
†10(i)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(i)(1).
†10(i)(2)	Memorandum of Agreement between Susan Tomasky and AEPSC dated January 3, 2001.	AEP 2000 Form 10-K, Ex 10(s), File No. 1-3525.
†10(i)(3)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K; Ex 10(i)(3).
†10(i)(4)	Letter Agreement dated June 4, 2004 between AEPSC and Carl English	AEP Form 10-Q, Ex 10(b), September 30, 2004
†10(j)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	AEP Form 10-Q, Ex 10, September 30, 1998, File No. 1-3525.
†10(j)(2)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K; Ex 10(j)(2).
†10(k)	AEP Change In Control Agreement, effective January 1, 2005.	AEP Form 8-K, Ex 10.1 dated January 10, 2005, File No. 1-3525.
†10(l)(1)	AEP System 2000 Long-Term Incentive Plan, as amended December 10, 2003.	2003 Form 10-K, Ex 10(m).
†10(l)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System 2000 Long-Term Incentive Plan, as amended	AEP Form 10-Q, Ex. 10(c), dated November 5, 2004.
†10(m)(1)	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.	CSW 1998 Form 10-K, Ex 18, File No. 1-1443.
†10(m)(2)	Certified AEP Utilities, Inc. (formerly CSW) Board Resolutions of July 16, 1996.	2003 Form 10-K, Ex 10(n)(3).
†10(n)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2003.	2003 Form 10-K, Ex 10(o)(1).
†10(o)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K; Ex 10(p).
†10(p)	Nuclear Key Contributor Retention Plan dated May 1, 2000.	2002 Form 10-K; Ex 10(q).
*†10(q)	Base Salaries for Named Executive Officers	
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the APCo 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of APCo	AEP 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT:	**CSPCo‡ File No. 1-2680**	
3(a)	Composite of Amended Articles of Incorporation of CSPCo, dated May 19, 1994.	1994 Form 10-K, Ex 3(c).
3(b)	Code of Regulations and By-Laws of CSPCo.	1987 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo and Bankers Trust Company, as Trustee.	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d); 1998 Form 10-K, Ex 4(c)(d).
4(b)	First Supplemental Indenture between CSPCo and Deutsche Bank Trust Company Americas, as Trustee, dated November 25, 2003, establishing terms of 4.40% Senior Notes, Series E, due 2010.	2003 Form 10-K, Ex 4(c).
4(c)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(d).
4(d)	First Supplemental Indenture, dated as of February 1, 2003, between CSPCo and Bank One, N.A., AS trustee, establishing the terms of 5.50% Senior Notes, Series A, due 2013 and 5.50% Senior Notes, Series C, due 2013.	2003 Form 10-K, Ex 4(e).
4(e)	Second Supplemental Indenture, dated as of February 1, 2003, between CSPCo and Bank One establishing the terms of 6.60% Senior Notes, Series B, due 2033 and 6.60% Senior Notes, Series D, due 2033.	2003 Form 10-K, Ex 4(f).
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(B); APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457; APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No. 1-3457.
10(a)(2)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); APCo 1992 Form 10-K, Ex 10(a)(2)(B), File No. 1-3457.
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e).
10(b)	Interconnection Agreement, dated July 6, 1951,	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b);

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	among APCo, CSPCo, KPCo, OPCo and I&M and AEPSC, as amended.	AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525.
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo, and with AEPSC as agent, as amended.	AEP 1985 Form 10-K, Ex 10(b), File No. 1-3525; AEP 1988 Form 10-K, Ex 10(b)(2) File No. 1-3525.
*10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525.
10(f)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation.	AEP 1997 Form 10-K, Ex 10(f), File No. 1-3525.
10(f)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger.	Form 8-K, Ex 10, dated December 15, 1999.
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the CSPCo 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of CSPCo	AEP 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT:	*I&M‡ File No. 1-3570*	
3(a)	Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997	1996 Form 10-K, Ex 3(c).
3(b)	By-Laws of I&M, amended as of November 28, 2001.	2001 Form 10-K, Ex 3(d).

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(a)	Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee.	Registration Statement No. 333-88523, Ex 4(a)(b)(c); Registration Statement No. 333-58656, Ex 4(b)(c); Registration Statement No. 333-108975, Ex 4(b)(c)(d)].
4(b)	Company Order and Officer's Certificate, dated November 10, 2004, establishing terms of 5.05% Senior Notes, Series F, due 2014.	Form 8-K, Ex. 4(a), dated November 16, 2004
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); APCo 1989 Form 10-K, File No. 1-3457, Ex 10(a)(1)(F); APCo 1992 Form 10-K, File No. 1-3457, Ex 10(a)(1)(B).
10(a)(2)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); APCo Form 10-K, File No. 1-3457, Ex 10(a)(2)(B).
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended	Registration Statement No. 2-60015, Ex 5(e).
10(a)(4)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); APCo 1992 Form 10-K, File No. 1-3457, Ex 10(a)(2)(B).
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M, and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, File No. 1-3525, Ex 10(a)(3).
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	AEP 1985 Form 10-K, File No. 1-3525, Ex 10(b); AEP 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2).
*10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	AEP 1996 Form 10-K, File No. 1-3525, Ex 10(l).
10(f)	Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32753, Ex 28(a)(1-6)(C); 1993 Form 10-K, Ex 10(e)(1-6)(B).
10(g)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation.	AEP 1997 Form 10-K, File No. 1-3525, Ex 10(f).
10(g)(2)	Amendment No. 1, dated as of December 31, 1999,	Form 8-K, Ex 10, December 15, 1999.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	to the Agreement and Plan of Merger	
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the I&M 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of I&M.	AEP 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: KPCo‡ File No. 1-6858		
3(a)	Restated Articles of Incorporation of KPCo.	1991 Form 10-K, Ex 3(a).
3(b)	By-Laws of KPCo, amended as of June 15, 2000.	2000 Form 10-K, Ex 3(b).
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between KPCo and Bankers Trust Company, as Trustee.	Registration Statement No. 333-75785, Ex 4(a)(b)(c)(d); Registration Statement No. 333-87216, Ex 4(e)(f); 2002 Form 10-K, Ex 4(c)(d)(e).
10(a)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, File No. 1-3525, Ex 10(a)(3).
10(b)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	AEP 1985 Form 10-K, File No. 1-3525, Ex 10(b); AEP 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2).
*10(c)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(c)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(c)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(d)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	AEP 1996 Form 10-K, File No. 1-3525, Ex 10(l).
10(e)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition	AEP 1997 Form 10-K, File No. 1-3525, Ex 10(f).

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Corporation and Central and South West Corporation	
10(e)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger.	Form 8-K, Ex 10, dated December 15, 1999.
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the KPCo 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT:	**OPCo‡ File No.1-6543**	
3(a)	Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.	Form 10-Q, Ex 3(e), June 30, 2002.
3(b)	Code of Regulations of OPCo.	1990 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now Deutsche Bank Trust Company Americas), as Trustee.	Registration Statement No. 333-49595, Ex 4(a)(b)(c); Registration Statement No. 333-106242, Ex 4(b)(c)(d); Registration Statement No. 333-75783, Ex 4(b)(c).
4(b)	First Supplemental Indenture between OPCo and Deutsche Bank Trust Company Americas, as Trustee, dated July 11, 2003, establishing terms of 4.85% Senior Notes, Series H, due 2014.	2003 Form 10-K, Ex 4(c).
4(c)	Second Supplemental Indenture between OPCo and Deutsche Bank Trust Company Americas, as Trustee, dated July 11, 2003, establishing terms of 6.375% Senior Notes, Series I, due 2033.	2003 Form 10-K, Ex 4(d).
4(d)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(e).
4(e)	First Supplemental Indenture, dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series D, due 2013 and 5.50% Senior Notes, Series F, due 2013.	2003 Form 10-K, Ex 4(f).
4(f)	Second Supplemental Indenture, dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee, establishing the terms of 6.60%	2003 Form 10-K, Ex 4(g).

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Senior Notes, Series E, due 2033 and 6.60% Senior Notes, Series G, due 2033.	
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); APCo Form 10-K, File No. 1-3457, Ex 10(a)(1)(F); APCo Form 10-K, File No. 1-3457, Ex 10(a)(1)(B).
10(a)(2)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); APCo Form 10-K, File No. 1-3457, Ex 10(a)(2)(B).
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e).
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, File 1-3525, Ex 10(a)(3).
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent.	AEP 1985 Form 10-K, File No. 1-3525, Ex 10(b); AEP 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2).
*10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	AEP 1996 Form 10-K, File No. 1-3525, Ex 10(l).
10(f)(1)	Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	1993 Form 10-K, Ex 10(f). 2003 Form 10-K, Ex 10(e)
10(f)(2)	Amendment No. 9, dated July 1, 2003, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	Form 10-Q, Ex 10(a), September 30, 2004.
10(g)	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested).	1994 Form 10-K, Ex 10(l)(2).
10(h)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, by and among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation.	AEP 1997 Form 10-K, File No. 1-3525, Ex 10(f).

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(h)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger.	Form 8-K, Ex 10, dated December 15, 1999.
†10(i)	AEP System Senior Officer Annual Incentive Compensation Plan.	AEP 1996 Form 10-K, Ex 10(i)(1), File No. 1-3525.
†10(j)(1)(A)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.	AEP 2000 Form 10-K, Ex 10(j)(1)(A), File No. 1-3525.
†10(j)(1)(B)	First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.	2002 Form 10-K; Ex 10(i)(1)(B)
†10(j)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of September 1, 2004 (Non-Qualified).	AEP Form 8-K, Ex 99.1, dated September 1, 2004.
†10(j)(3)	Umbrella Trust for Executives.	AEP 1993 Form 10-K, Ex 10(g)(3), File No. 1-3525.
†10(k)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(j)(1).
†10(k)(2)	Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.	AEP 2000 Form 10-K, Ex 10(s), File No. 1-3525.
†10(k)(3)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(j)(3).
†10(k)(4)	Letter Agreement dated June 4, 2004 between AEPSC and Carl English	AEP Form 10-Q, Ex 10(b), September 30, 2004, File No. 1-3525,
†10(l)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	AEP Form 10-Q, Ex 10, September 30, 1998, File No. 1-3525,.
†10(l)(2)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K; Ex 10(k)(2).
†10(m)	AEP Change In Control Agreement, effective January 1, 2005.	AEP Form 8-K, Ex 10.1, dated January 10, 2005, File No. 1-3525.
†10(n)(1)	AEP System 2000 Long-Term Incentive Plan, as amended December 10, 2003.	2003 Form 10-K, Ex 10(n).
†10(n)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System 2000 Long-Term Incentive Plan, as amended	AEP Form 10-Q, Ex. 10(c), dated November 5, 2004.
†10(o)(1)	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.	1998 Form 10-K, File No. 1-1443, Ex 18.
†10(o)(2)	Certified AEP Utilities, Inc. (formerly CSW) Board Resolutions of July 16, 1996.	2003 Form 10-K, Ex 10(o)(3).
†10(p)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2003.	2003 Form 10-K, Ex 10(p)(1).
†10(q)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(q).
†10(r)	Nuclear Key Contributor Retention Plan dated May 1, 2000.	2002 Form 10-K, Ex 10(r).
*†10(s)	Base Salaries for Named Executive Officers	
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the OPCo 2004 Annual	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of OPCo.	AEP 2004 Form 10-K, File No. 1-3525, Ex 21
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT:	**PSO‡ File No. 0-343**	
3(a)	Restated Certificate of Incorporation of PSO.	CSW 1996 Form U5S, File No. 1-1443, Ex B-3.1.
3(b)	By-Laws of PSO (amended as of June 28, 2000).	2002 Form 10-K, Ex 3(b).
4(a)	Indenture, dated July 1, 1945, between and Liberty Bank and Trust Company of Tulsa, National Association, as Trustee, as amended and supplemented.	Registration Statement No. 2-60712, Ex 5.03; Registration Statement No. 2-64432, Ex 2.02; Registration Statement No. 2-65871, Ex 2.02; Form U-1 No. 70-6822, Ex 2; Form U-1 No. 70-7234, Ex 3; Registration Statement No. 33-48650, Ex 4(b); Registration Statement No. 33-49143, Ex 4(c); Registration Statement No. 33-49575, Ex 4(b); 1993 Form 10-K, Ex 4(b); Form 8-K, Ex 4.01; dated March 4, 1996. Form 8-K, Ex 4.02, dated March 4, 1996; Form 8-K, Ex 4.03, dated March 4, 1996.
4(b)	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.	Registration Statement No. 333-100623, Exs 4(a)(b); 2002 Form 10-K; Ex 4(c).
4(c)	Third Supplemental Indenture, dated as of September 15, 2003, between PSO and The Bank of New York, as Trustee, establishing terms of the 4.85% Senior Notes, Series C, due 2010.	2003 Form 10-K, Ex 4(d).
4(d)	Fourth Supplemental Indenture, dated as of June 7, 2004 between PSO and The Bank of New York, as Trustee, establishing terms of the 4.70% Senior Notes, Series D, due 2009	Form 8-K, Ex 4(a), dated June 7, 2004
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K, Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K, Ex 10(b).

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the PSO 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of PSO.	AEP 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT:	**SWEPCo‡ File No. 1-3146**	
3(a)	Restated Certificate of Incorporation, as amended through May 6, 1997, including Certificate of Amendment of Restated Certificate of Incorporation.	Form 10-Q, Ex 3.4, March 31, 1997.
3(b)	By-Laws of SWEPCo (amended as of April 27, 2000).	Form 10-Q, Ex 3.3, March 31, 2000.
4(a)	Indenture, dated February 1, 1940, between SWEPCo and Continental Bank, National Association and M. J. Kruger, as Trustees, as amended and supplemented.	Registration Statement No. 2-60712, Ex 5.04; Registration Statement No. 2-61943, Ex 2.02; Registration Statement No. 2-66033, Ex 2.02; Registration Statement No. 2-71126, Ex 2.02; Registration Statement No. 2-77165, Ex 2.02; Form U-1 No. 70-7121, Ex 4; Form U-1 No. 70-7233, Ex 3; Form U-1 No. 70-7676, Ex 3; Form U-1 No. 70-7934, Ex 10; Form U-1 No. 72-8041, Ex 10(b); Form U-1 No. 70-8041, Ex 10(c); Form U-1 No. 70-8239, Ex 10(a).
4(b)	SWEPCO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCo: (1) Subordinated Indenture, dated as of September 1, 2003, between SWEPCo and the Bank of New York, as Trustee. (2) Amended and Restated Trust Agreement of SWEPCo Capital Trust I, dated as of September 1, 2003, among SWEPCo, as Depositor, the Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustees.	2003 Form 10-K, Ex 4(b).

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	(3) Guarantee Agreement, dated as of September 1, 2003, delivered by SWEPCo for the benefit of the holders of SWEPCo Capital Trust I's Preferred Securities. (4)First Supplemental Indenture dated as of October 1, 2003, providing for the issuance of Series B Junior Subordinated Debentures between SWEPCo, as Issuer and the Bank of New York, as Trustee (5)Agreement as to Expenses and Liabilities, dated as of October 1, 2003 between SWEPCo and SWEPCo Capital Trust I (included in Item (4) above as Ex 4(f)(i)(A).	
4(c)	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.	Registration Statement No. 333-87834, Ex 4(a)(b); Registration Statement No. 333-600632, Ex 4(b); Registration Statement No. 333-108045, Ex 4(b).
4(d)	Third Supplemental Indenture, between SWEPCo and The Bank of New York, as Trustees, dated April 11, 2003, establishing terms of 5.375% Senior Notes, Series C, due 2015.	2003 Form 10-K, Ex 4(d).
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the SWEPCo 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of SWEPCo.	AEP 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT:	**TCC‡ File No. 0-346**	
3(a)	Restated Articles of Incorporation Without Amendment, Articles of Correction to Restated Articles of Incorporation Without Amendment, Articles of Amendment to Restated Articles of	Form 10-Q, Ex 3.1, March 31, 1997.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Incorporation, Statements of Registered Office and/or Agent, and Articles of Amendment to the Articles of Incorporation.	
3(b)	Articles of Amendment to Restated Articles of Incorporation of TCC dated December 18, 2002.	2002 Form 10-K; Ex 3(b).
3(c)	By-Laws of TCC (amended as of April 19, 2000).	2000 Form 10-K, Ex 3(b).
4(a)	Indenture (for unsecured debt securities), dated as of November 15, 1999, between TCC and The Bank of New York, as Trustee, as amended and supplemented.	2000 Form 10-K, Ex 4(c)(d)(e).
4(b)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(d).
4(c)	First Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series A, due 2013 and 5.50% Senior Notes, Series D, due 2013.	2003 Form 10-K, Ex 4(e).
4(d)	Second Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 6.65% Senior Notes, Series B, due 2033 and 6.65% Senior Notes, Series E, due 2033.	2003 Form 10-K, Ex 4(f).
4(e)	Third Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 3.00% Senior Notes, Series C, due 2005 and 3.00% Senior Notes, Series F, due 2005.	2003 Form 10-K, Ex 4(g).
4(f)	Fourth Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of Floating Rate Notes, Series A, due 2005 and Floating Rate Notes, Series B, due 2005.	2003 Form 10-K, Ex 4(h).
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
10(c)	Purchase and Sale Agreement, dated as of September 3, 2004, by and between TCC and City of San Antonio (acting by and through the City Public Service Board of San Antonio) and Texas Genco, L.P.	Form 10-Q, Ex. 10(a), September 30, 2004.
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the TCC 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
21	List of subsidiaries of TCC.	AEP 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT:	**TNC‡ File No. 0-340**	
3(a)	Restated Articles of Incorporation, as amended, and Articles of Amendment to the Articles of Incorporation.	1996 Form 10-K, Ex 3.5.
3(b)	Articles of Amendment to Restated Articles of Incorporation of TNC dated December 17, 2002.	2002 Form 10-K; Ex 3(b).
3(c)	By-Laws of TNC (amended as of May 1, 2000).	Form 10-Q, Ex 3.4, March 31, 2000.
4(a)	Indenture, dated August 1, 1943, between TNC and Harris Trust and Savings Bank and J. Bartolini, as Trustees, as amended and supplemented.	Registration Statement No. 2-60712, Ex 5.05; Registration Statement No. 2-63931, Ex 2.02; Registration Statement No. 2-74408, Ex 4.02; Form U-1 No. 70-6820, Ex 12; Form U-1 No. 70-6925, Ex 13; Registration Statement No. 2-98843, Ex 4(b); Form U-1 No. 70-7237, Ex 4; Form U-1 No. 70-7719, Ex 3; Form U-1 No. 70-7936, Ex 10; Form U-1 No. 70-8057, Ex 10; Form U-1 No. 70-8265, Ex 10; Form U-1 No. 70-8057, Ex 10(b); Form U-1 No. 70-8057, Ex 10(c).
4(b)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between TNC and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(b).
4(c)	First Supplemental Indenture, dated as of February 1, 2003, between TNC and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series A, due 2013 and 5.50% Senior Notes, Series D, due 2013.	2003 Form 10-K, Ex 4(c).
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
*12	Statement re: Computation of Ratios.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*13	Copy of those portions of the TNC 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	

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

2004 Annual Reports

American Electric Power Company, Inc.

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

Audited Financial Statements and
Management's Financial Discussion and Analysis

AMERICAN ELECTRIC POWER

AEP: America's Energy Partner®

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an 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.

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.

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. AND SUBSIDIARY COMPANIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

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
<u>Changes in Operating And Other Expenses:</u>		
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.

Other

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.

<u>FERC Order on Regional Through and Out Rates</u>

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.

<u>Pension and Postretirement Benefit Plans</u>

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%.

Revenue Recognition – Accounting for Derivative Instruments

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.

<u>Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets (Liabilities)</u>

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.

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.

/s/ 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.

/s/ 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 A-64.

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	Common Stock 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	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.

<u>2003</u>

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
				(in millions)				
Assets:								
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:

	Underfunded Pension Plans	
End of Year	2004	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	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		Other Postretirement Benefit Plans	
	2004	2003	2004	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	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	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	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	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:

	2004 Quarterly Periods Ended			
(In Millions – Except Per Share Amounts)	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

	2003 Quarterly Periods Ended			
(In Millions – Except Per Share Amounts)	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.

AEP GENERATING COMPANY

AEP GENERATING COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 241,788	$ 233,165	$ 213,281	$ 227,548	$ 228,516
Operating Income	6,904	7,174	6,129	6,977	8,424
Interest Charges	2,446	2,550	2,258	2,586	3,869
Net Income	7,842	7,964	7,552	7,875	7,984
BALANCE SHEETS DATA					
Electric Utility Plant	$ 689,577	$ 674,055	$ 652,213	$ 648,254	$ 642,302
Accumulated Depreciation and Amortization	368,484	351,062	330,187	310,804	290,858
Net Electric Utility Plant	$ 321,093	$ 322,993	$ 322,026	$ 337,450	$ 351,444
TOTAL ASSETS	$ 376,393	$ 380,045	$ 377,716	$ 387,688	$ 399,310
Common Shareholder's Equity	48,671	45,875	42,597	38,195	34,156
Long-term Debt (a)	44,820	44,811	44,802	44,793	44,808
Obligations Under Capital Leases (a)	12,474(b)	269	501	311	591

(a) Including portion due within one year.
(b) Increased primarily due to a new coal transportation lease. See Note 15.

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

AEGCo, co-owner of the Rockport Plant, is engaged in the generation and wholesale sale of electric power to two affiliates, I&M and KPCo, under long-term agreements. I&M is the operator and the other co-owner of the Rockport Plant.

Operating revenues are derived from the sale of Rockport Plant energy and capacity to I&M and KPCo pursuant to FERC approved long-term unit power agreements. Under the terms of its unit power agreement, I&M agreed to purchase all of our Rockport energy and capacity unless it is sold to other utilities or affiliates. I&M assigned 30% of its rights to energy and capacity to KPCo. In December 2004, KPSC and the FERC approved a Stipulation and Settlement Agreement which, among other things, extends the unit power agreement with KPCo until December 7, 2022.

The unit power agreements provide for a FERC approved rate of return on common equity, a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes. Under the terms of the unit power agreements, AEGCo accumulates all expenses monthly and prepares bills for its affiliates. In the month the expenses are incurred, AEGCo recognizes the billing revenues and establishes a receivable from the affiliated companies. Costs of operating the plant are divided between the co-owners.

Results of Operations

Net Income decreased $0.1 million for 2004 compared with 2003. The fluctuation in Net Income is a result of terms in the unit power agreements which allow for a return on total capital of the Rockport Plant calculated and adjusted monthly.

2004 Compared to 2003

Operating Income

Operating Income decreased $0.3 million from the prior year. The largest variances related to:

- A $3.2 million increase in Fuel for Electric Generation expense primarily due to an 8.7% increase in average fuel costs per KWH generated.
- A $1.9 million increase in Income Taxes. See Income Taxes section below for further discussion.
- A $1.8 million increase in Maintenance expenses as a result of increased planned boiler inspections and forced repairs.
- A $0.8 million increase in Taxes Other Than Income Taxes as a result of Indiana property tax reappraisals.
- A $0.7 million increase in Depreciation and Amortization reflecting an increase in assets being depreciated.
- A $0.5 million increase in Other Operation expenses reflecting increased employee pension and benefit costs.

The above expense increases were recovered per the terms of the unit power agreement by:

- An $8.6 million increase in Operating Revenues as a result of increased recoverable expenses.

Income Taxes

The effective tax rates for 2004 and 2003 were (1.5)% and (31.5)%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is primarily due to amortization of investment tax credits, flow-through of book versus tax temporary differences, and state income taxes. The increase in the effective tax rate is primarily due to higher state income taxes and changes in flow-through temporary differences.

Off-Balance Sheet Arrangements

Rockport Plant Unit 2

In 1989, AEGCo and I&M entered into a sale and leaseback transaction with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $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 lease footnote (see Note 15). 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.

Our contractual obligations include amounts reported on the 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
Advances from Affiliates (a)	$ 26.9	$ -	$ -	$ -	$ 26.9
Capital Lease Obligations (b)	1.0	2.0	1.9	18.0	22.9
Noncancelable Operating Leases (b)	74.0	147.9	147.9	960.2	1,330.0
Total	$ 101.9	$ 149.9	$ 149.8	$ 978.2	$ 1,379.8

(a) Represents short-term borrowings from the Utility Money Pool.
(b) See Note 15. The lease of the Plant is reported in Noncancelable Operating Leases.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" beginning on M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, income taxes, and the impact of new accounting pronouncements.

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES	$ 241,788	$ 233,165	$ 213,281
OPERATING EXPENSES			
Fuel for Electric Generation	112,470	109,238	89,105
Rent – Rockport Plant Unit 2	68,283	68,283	68,283
Other Operation	10,866	10,399	12,924
Maintenance	12,152	10,346	9,418
Depreciation and Amortization	23,390	22,686	22,560
Taxes Other Than Income Taxes	4,181	3,396	3,281
Income Taxes	3,542	1,643	1,581
TOTAL	234,884	225,991	207,152
OPERATING INCOME	6,904	7,174	6,129
Nonoperating Income	43	151	344
Nonoperating Expenses	317	361	199
Nonoperating Income Tax Credits	3,658	3,550	3,536
Interest Charges	2,446	2,550	2,258
NET INCOME	$ 7,842	$ 7,964	$ 7,552

STATEMENTS OF RETAINED EARNINGS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
BALANCE AT BEGINNING OF PERIOD	$ 21,441	$ 18,163	$ 13,761
Net Income	7,842	7,964	7,552
Cash Dividends Declared	5,046	4,686	3,150
BALANCE AT END OF PERIOD	$ 24,237	$ 21,441	$ 18,163

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 681,254	$ 645,251
General	3,739	4,063
Construction Work in Progress	7,729	24,741
Total	692,722	674,055
Accumulated Depreciation and Amortization	368,484	351,062
TOTAL - NET	324,238	322,993
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	119	119
CURRENT ASSETS		
Accounts Receivable – Affiliated Companies	23,078	24,748
Fuel	16,404	20,139
Materials and Supplies	5,962	5,419
TOTAL	45,444	50,306
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,496	4,733
Asset Retirement Obligations	1,117	928
Deferred Property Taxes	557	502
Other Deferred Charges	422	464
TOTAL	6,592	6,627
TOTAL ASSETS	$ 376,393	$ 380,045

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2004 and 2003

		2004		2003
CAPITALIZATION		(in thousands)		
Common Shareholder's Equity:				
Common Stock – $1,000 Par Value Per Share:				
Authorized and Outstanding – 1,000 Shares	$	1,000	$	1,000
Paid-in Capital		23,434		23,434
Retained Earnings		24,237		21,441
Total Common Shareholder's Equity		48,671		45,875
Long-term Debt		44,820		44,811
TOTAL		93,491		90,686
CURRENT LIABILITIES				
Advances from Affiliates		26,915		36,892
Accounts Payable:				
General		443		498
Affiliated Companies		17,905		15,911
Taxes Accrued		8,806		6,070
Interest Accrued		911		911
Obligations Under Capital Leases		210		87
Rent Accrued – Rockport Plant Unit 2		4,963		4,963
Other		73		-
TOTAL		60,226		65,332
DEFERRED CREDITS AND OTHER LIABILITIES				
Deferred Income Taxes		24,762		24,329
Regulatory Liabilities:				
Asset Removal Costs		25,428		27,822
Deferred Investment Tax Credits		46,250		49,589
SFAS 109 Regulatory Liability, Net		12,852		15,505
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2		99,904		105,475
Obligations Under Capital Leases		12,264		182
Asset Retirement Obligations		1,216		1,125
TOTAL		222,676		224,027
Commitments and Contingencies (Note 7)				
TOTAL CAPITALIZATION AND LIABILITIES	$	376,393	$	380,045

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 7,842	$ 7,964	$ 7,552
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	23,390	22,686	22,560
Deferred Income Taxes	(2,219)	(5,838)	(5,028)
Deferred Investment Tax Credits	(3,339)	(3,354)	(3,361)
Amortization of Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	(5,571)	(5,571)	(5,571)
Changes in Other Noncurrent Assets	3,455	3,486	(5,455)
Changes in Other Noncurrent Liabilities	(2,511)	1,120	102
Changes in Components of Working Capital:			
Accounts Receivable	1,670	(6,294)	4,037
Fuel, Materials and Supplies	3,192	(385)	(5,450)
Accounts Payable	1,939	476	6,697
Taxes Accrued	2,736	3,743	(2,450)
Other Current Assets	-	-	244
Other Current Liabilities	196	(113)	(2,397)
Net Cash Flows From Operating Activities	30,780	17,920	11,480
INVESTING ACTIVITIES			
Construction Expenditures	(15,757)	(22,197)	(5,298)
Change in Other Cash Deposits, Net	-	-	983
Proceeds from Sale of Assets	-	105	-
Net Cash Flows Used For Investing Activities	(15,757)	(22,092)	(4,315)
FINANCING ACTIVITIES			
Change in Advances to/from Affiliates, Net	(9,977)	8,858	(4,015)
Dividends Paid	(5,046)	(4,686)	(3,150)
Net Cash Flows From (Used For) Financing Activities	(15,023)	4,172	(7,165)
Net Change in Cash and Cash Equivalents	-	-	-
Cash and Cash Equivalents at Beginning of Period	-	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -	$ -

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $2,179,000, $2,283,000 and $2,019,000 and for income taxes was $542,000, $6,483,000 and $7,884,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $12,297,000.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
SCHEDULE OF LONG-TERM DEBT
December 31, 2004 and 2003
(in thousands)

			2004		2003
LONG-TERM DEBT -					
Installment Purchase Contracts – City of Rockport (a)					
Series	Due Date				
1995 A	2025 (b)	$	22,500	$	22,500
1995 B	2025 (b)		22,500		22,500
Unamortized Discount			(180)		(189)
TOTAL LONG-TERM DEBT		$	44,820	$	44,811

(a) We entered into installment purchase contracts in connection with the issuance of pollution control revenue bonds by the City of Rockport, Indiana. The terms of the installment purchase contracts require our payment of amounts sufficient to enable the payment of interest and principal on the related pollution control revenue bonds issued to refinance the construction costs of pollution control facilities at the Rockport Plant. The bonds due in 2025 are subject to mandatory tender for purchase in July 2006. Consequently, the bonds have been classified for repayment purposes in 2006.

(b) These series have an adjustable interest rate that we can designate as a daily, weekly, commercial paper or term rate. In July 2001, we selected a term rate of 4.05% for five years ending July 12, 2006.

None of our long-term debt obligations have been guaranteed or secured by AEP or any of our affiliates.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to AEGCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to AEGCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
AEP Generating Company:

We have audited the accompanying balance sheets of AEP Generating Company as of December 31, 2004 and 2003, and the related statements of income, retained earnings, and cash flows 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Generating Company as of December 31, 2004 and 2003, and the results of its operations and its 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 1,175,266	$ 1,747,511	$ 1,690,493	$ 1,738,837	$ 1,770,402
Operating Income	196,019	321,540	393,733	295,731	307,098
Carrying Costs on Stranded Cost Recovery (a)	301,644	-	-	-	-
Interest Charges	123,785	133,812	125,871	116,268	124,766
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	294,656	217,547	275,941	182,278	189,567
Extraordinary Loss on Stranded Cost Recovery, Net of Tax (a)	(120,534)	-	-	-	-
Cumulative Effect of Accounting Change, Net of Tax	-	122	-	-	-
Net Income	174,122	217,669	275,941	182,278	189,567
BALANCE SHEETS DATA					
Electric Utility Plant	$ 2,492,798	$ 2,425,038	$ 2,334,794	$ 2,231,287	$ 2,097,497
Accumulated Depreciation and Amortization	725,225	695,359	662,345	616,526	570,522
Net Electric Utility Plant	$ 1,767,573	$ 1,729,679	$ 1,672,449	$ 1,614,761	$ 1,526,975
Total Assets	$ 5,695,790	$ 5,854,429	$ 5,515,723	$ 4,989,381	$ 5,556,275
Common Shareholder's Equity	1,268,643	1,209,049	1,101,134	1,400,100	1,366,123
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940	5,942	5,952	5,951
Trust Preferred Securities (b)	-	-	136,250	136,250	148,500
Long-term Debt (c)	1,907,294	2,291,625	1,438,565	1,253,768	1,454,559
Obligations Under Capital Leases (c)	880	1,043	-	-	-

(a) See "Carrying Costs on Net True-up Regulatory Assets" and "Net Stranded Generation Costs" sections of Note 6.
(b) See "Trust Preferred Securities" section of Note 16.
(c) Including portion due within one year.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

TCC is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power. We consolidate AEP Texas Central Transition Funding LLC, our wholly-owned subsidiary. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. We also sell electric power at wholesale to other utilities, a municipality, rural electric cooperatives and REPs in Texas.

Power pool members are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

2004 Compared to 2003

Net Income decreased $44 million for 2004. The major factors driving the decline are decreased revenues associated with establishing regulatory assets in Texas in 2003 and the extraordinary item related to stranded cost in 2004, offset in part in 2004 by the cessation of depreciation on plants held for sale and the capitalization of carrying costs on recoverable stranded costs. The sale of several of our generation plants in July 2004 affected numerous line items on the income statement and reduced the amount of margins recognized from the generation operations.

Operating Income

Operating Income decreased $126 million primarily due to:

- A $215 million decrease in revenues associated with establishing regulatory assets in Texas in 2003 (see "Texas Restructuring" and "Wholesale Capacity Auction True-up" section of Note 6).
- A $214 million decrease in off-system sales, including those to REPs, primarily due to lower KWH sales of 36%. The decrease in KWH sales is due to customer choice in Texas and the sale of certain generation plants.

- A $127 million decrease in Reliability Must Run (RMR) revenues from ERCOT, which includes both a fuel recovery decrease of $108 million and a fixed cost component decrease of $19 million due to TCC no longer having RMR plants. In 2004, RMR revenues totaled $115 million of which $16 million was for reimbursement of fixed costs.
- A $24 million decrease in revenues from ERCOT for various services including balancing energy and prior year adjustments made by ERCOT.
- A $13 million decrease in margins from risk management activities.
- A $12 million increase in Other Operation expenses primarily due to a $10 million increase of ERCOT-related transmission expense and affiliated ancillary services resulting from revised data received from ERCOT for the years 2001-2003; a $4 million increase in distribution related expense; and a $6 million increase in general and administrative expenses; offset by a $9 million decrease in production expenses due to the sale of certain generation plants.
- A $10 million decrease in Qualified Scheduling Entity (QSE) fees primarily due to one REP not using TCC as their QSE in 2004.

The decrease in Operating Income was partially offset by:

- A $303 million net decrease in fuel and purchased power expenses. KWHs purchased decreased 51% while the per unit cost increased 20%. Per unit generation costs decreased 29% and KWHs generated decreased 21% due to the sale of certain generation plants and the fact that lower cost nuclear fuel generation became a larger part of the generation mix after the sale.
- A $75 million decrease in Depreciation and Amortization expenses primarily due to the cessation of depreciation on plants sold and plants classified as held for sale (see "Dispositions" and "Assets Held for Sale" sections of Note 10).
- A $71 million decrease in Income Taxes. See Income Taxes section below for further discussion.
- A $21 million increase in revenues due to a decrease in provisions for rate refunds primarily due to fuel reconciliation issues (see "TCC Fuel Reconciliation" section of Note 4).
- A $15 million increase in transmission revenue primarily due to affiliated open access transmission tariff (including an $8 million true-up for prior years recorded in 2004 resulting from revised data received from ERCOT for the years 2001-2003) and ancillary services.
- An $8 million decrease in Maintenance expenses primarily due to the sale of certain generation plants.

Other Impacts on Earnings

We recorded in income a carrying cost of $302 million on stranded cost recovery (see "Carrying Costs on Net True-up Regulatory Assets" section of Note 6).

Nonoperating income decreased $8 million primarily due to a decrease in risk management activities.

Interest Charges decreased $10 million primarily due to the defeasance of $112 million of First Mortgage Bonds, and the resultant deferral of the interest cost as a regulatory asset related to the cost of the sale of generation assets, the redemption of the 8% Notes Payable to Trust, and other financing activities.

Income Taxes

The effective tax rates for 2004 and 2003 were 31.4% and 32.6%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35.0% is due to permanent differences, amortization of investment tax credits, consolidated tax savings, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Extraordinary Loss on Stranded Cost Recovery, Net of Tax

See "Texas Restructuring" and "Net Stranded Generation Costs" sections of Note 6 for a discussion of net adjustments of stranded costs recorded in the fourth quarter of 2004.

2003 Compared to 2002

Net Income decreased $58 million for 2003. The decrease is primarily due to an increased provision for refunds of $85 million ($55 million after tax) and a decrease in the recognition of noncash earnings related to legislatively-mandated capacity auctions and regulatory assets established in Texas of $29 million net of tax. Additionally, income from transactions with ERCOT increased significantly due mainly to Texas Restructuring Legislation.

Since REPs are the electricity suppliers to retail customers in the ERCOT area, we sell our generation to the REPs and other market participants and provide transmission and distribution services to retail customers of the REPs in our service territory. As a result of the provision of retail electric service by REPs, effective January 1, 2002, we no longer supply electricity directly to retail customers. The implementation of REPs as suppliers to retail customers has caused a shift in our sales as further described below.

In December 2002, AEP sold Mutual Energy CPL to an unrelated third party, who assumed the obligations of the affiliated REP including the provision of price-to-beat rates under the Texas Restructuring Legislation. Prior to the sale, during 2002, sales to Mutual Energy CPL were classified as Sales to AEP Affiliates. Subsequent to the sale, energy transactions and delivery charges with Mutual Energy CPL are classified as Electric Generation, Transmission and Distribution.

Operating Income

Operating Income decreased $72 million primarily due to:

- A $197 million net increase in fuel and purchased power expenses to replace portions of the energy from the non-RMR mothballed plants and the unscheduled forced outage at the STP nuclear unit. KWHs purchased increased 47% while the cost increased 54%. Although the KWHs generated decreased, fuel costs increased 16% due to higher per unit costs attributable mostly to natural gas.
- An $85 million increase in provisions for rate refunds primarily due to 2003 Texas fuel issues (see "TCC Fuel Reconciliation" section of Note 4).
- A $59 million decrease in revenue due to the 2002 interchange cost reconstruction adjustments with an offsetting $51 million decrease in purchased power.
- A $44 million decrease in revenues associated with establishing regulatory assets in Texas in 2003 (see "Texas Restructuring" section of Note 6). These revenues did not continue after 2003.
- A $24 million decrease in retail revenues driven by a 9% decrease in cooling degree-days offset by a slight increase in heating degree days. Average price per KWH decreased 2%.
- An $8 million increase in Maintenance expense primarily due to the STP Unit 2 forced outage in the first quarter of 2003, and the STP Unit 1 scheduled refueling outage and forced outage in the second and third quarters of 2003.
- A $7 million decrease in revenues from ERCOT for various services, including balancing energy.
- A $7 million decrease in off-system sales, including those to REPs, primarily due to a decrease in the overall average price per KWH and higher KWH sales of 2%.

The decrease in Operating Income was partially offset by:

- A $214 million increase in RMR revenues from ERCOT which include both fuel recovery and a fixed cost component of $35 million (see "Texas Plants" in Note 10 for discussion of RMR facilities).
- A $41 million decrease in Income Taxes. See Income Taxes section below for further discussion.
- A $31 million increase in margins resulting from risk management activities.
- A $25 million increase in other operating revenue comprised primarily of miscellaneous service revenue and fees as a result of the Texas Restructuring Legislation.
- A $24 million decrease in Depreciation and Amortization expense primarily due to decreases resulting from ARO of $16 million (see "Asset Retirement Obligations" in Note 2) and reduced depreciable plant by $6 million due to the mothballing of certain generating units in 2002.
- A $7 million decrease in Other Operation expense primarily due to lower distribution and customer related expenses in 2003, offset in part by $16 million of accretion expense associated with the implementation of SFAS 143, as well as increased costs of $6 million related to 2003 ERCOT transmission charges.

- A $3 million decrease in Taxes Other Than Income Taxes primarily due to reduced gross receipt taxes as a result of the sale of the Texas REPs, partially offset by higher property taxes.

Other Impacts on Earnings

Nonoperating Income increased $1 million. While 2003 gains from risk management activities increased $33 million, they are almost totally offset by lower 2003 revenues of $33 million from third party nonutility energy related construction projects.

Nonoperating Expense decreased $25 million primarily due to lower nonutility expenses associated with energy related construction projects for third parties.

Interest Charges increased $8 million primarily due to the replacement of lower cost short-term floating rate debt with longer-term higher cost fixed rate debt.

Income Taxes

The effective tax rates for 2003 and 2002 were 32.6% and 34.0%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35.0% is due to permanent differences, amortization of investment tax credits, consolidated tax savings, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Change

This amount represents the one-time after tax effect of the application of EITF 02-3 (see "Accounting for Risk Management Contracts" in Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A
Senior Unsecured Debt	Baa2	BBB	A-

Cash Flow

Cash flows for the year ended December 31, 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(in thousands)	
Cash and cash equivalents at beginning of period	$ 760	$ 807	$ 10,610
Cash flows from (used for):			
Operating activities	274,110	357,378	128,109
Investing activities	216,561	(104,980)	(216,432)
Financing activities	(491,431)	(252,445)	78,520
Net decrease in cash and cash equivalents	(760)	(47)	(9,803)
Cash and cash equivalents at end of period	$ -	$ 760	$ 807

Operating Activities

Our net cash flows from operating activities were $274 million in 2004. We produced income of $174 million during the period and noncash items of $123 million for Depreciation and Amortization, $121 million for an Extraordinary Loss on Stranded Cost Recovery and $(302) million for Carrying Costs on Stranded Cost Recovery.

See "Results of Operations" for discussions of these items. The change in Other Noncurrent Assets and other liabilities are primarily due to additional pension plan funding during the current year. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $117 million change in Taxes Accrued. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP 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.

Our net cash flows from operating activities were $357 million in 2003. We produced income of $218 million during the period and noncash items of $198 million for Depreciation and Amortization (see "Results of Operations) and $(218) million for Wholesale Capacity Auction True-up (see "Texas Restructuring" and "Wholesale Capacity Auction True-up" in Note 6). The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are a $56 million change in Accounts Payable primarily due to increased payables related to gas purchases and a $42 million change in Taxes Accrued as a result of taxes that were accrued during 2003 in excess of the amount remitted to the government.

Our net cash flows from operating activities were $128 million in 2002. We produced income of $276 million during the period and noncash items of $222 million for Depreciation and Amortization (see "Results of Operations), $114 million for Deferred Income Taxes and $(262) million for Wholesale Capacity Auction True-up (see "Texas Restructuring" and "Wholesale Capacity Auction True-up" section of Note 6). Deferred Income Taxes of $114 million were primarily due to the recording of deferred taxes related to the Wholesale Capacity Auction True-up. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $(217) million change in Accounts Receivable, Net primarily due to increased receivables related to the changes associated with the Texas Restructuring Legislation and an adjustment to the interchange cost reconstruction system.

Investing Activities

Our net cash flows from investing activities in 2004 were $217 million primarily due to $430 million in proceeds from the sale of several of our generation plants offset in part by $121 million of construction expenditures focused on improved service reliability projects for transmission and distribution systems.

Our net cash flows used for investing activities in 2003 were $105 million primarily due to construction expenditures focused on improved service reliability projects for transmission and distribution systems.

Our net cash flows used for investing activities in 2002 were $216 million primarily due to construction expenditures.

Financing Activities

Our net cash flows used for financing activities in 2004 were $491 million primarily due to the retirement of long-term debt and payment of dividends on common stock mainly with funds received from the sale of generation plants.

Our net cash flows used for financing activities in 2003 were $252 million primarily due to replacing both short and long-term debt with proceeds from new borrowings.

Our net cash flows from financing activities in 2002 were $79 million primarily due to the issuance of short-term debt. This issuance was partially offset by the retirement of common stock and decreased borrowing from the Utility Money Pool resulting from TCC Transition Funding new debt.

In February 2005, we reissued $162 million Matagorda County Navigation District Installment Purchase Contracts due May 1, 2030 that were put to us in November 2004. These bonds had not been retired as we 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.

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)	$ 365.7	$ 205.6	$ 122.3	$ 1,216.6	$ 1,910.2
Advances from Affiliates (b)	0.2	-	-	-	0.2
Capital Lease Obligations (c)	0.5	0.4	0.1	-	1.0
Noncancelable Operating Leases (c)	5.8	7.6	5.1	6.2	24.7
Energy and Capacity Purchase Contracts (d)	22.9	46.1	41.8	96.7	207.5
Total	$ 395.1	$ 259.7	$ 169.3	$ 1,319.5	$ 2,143.6

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.
(b) Represents short-term borrowings from the Utility Money Pool.
(c) See Note 15.
(d) Represents contractual cash flows of energy and capacity purchase contracts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2004 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)	$ -	$ 43.4	$ -	$ -	$ 43.4
Guarantees of Our Performance (b)	-	129.0	-	-	129.0
Transmission Facilities for Third Parties (c)	24.4	29.6	14.0	24.8	92.8
Total	$ 24.4	$ 202.0	$ 14.0	$ 24.8	$ 265.2

(a) We have issued standby letters of credit to third parties. These letters of credit cover 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 $43 million maturing in November 2005. There is no recourse to third parties in the event these letters of credit are drawn.
(b) See Note 8.
(c) 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.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

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

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

Total MTM Risk Management Contract Net Assets at December 31, 2003	$	11,942
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(5,033)
Fair Value of New Contracts When Entered During the Period (b)		1,175
Net Option Premiums Paid/(Received) (c)		(123)
Change in Fair Value Due to Valuation Methodology Changes (d)		110
Changes in Fair Value of Risk Management Contracts (e)		1,630
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)		-
Total MTM Risk Management Contract Net Assets		9,701
Net Cash Flow Hedge Contracts (g)		565
Total MTM Risk Management Contract Net Assets at December 31, 2004	$	10,266

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.
(b) "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 that were 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, 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 Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

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

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 10,107	$ 3,941	$ 14,048
Noncurrent Assets	9,504	4	9,508
Total MTM Derivative Contract Assets	19,611	3,945	23,556
Current Liabilities	(5,277)	(3,117)	(8,394)
Noncurrent Liabilities	(4,633)	(263)	(4,896)
Total MTM Derivative Contract Liabilities	(9,910)	(3,380)	(13,290)
Total MTM Derivative Contract Net Assets	$ 9,701	$ 565	$ 10,266

(a) Does not include Cash Flow 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of December 31, 2004
(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (1,280)	$ (46)	$ 644	$ -	$ -	$ -	$ (682)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	6,331	1,862	1,604	781	-	-	10,578
Prices Based on Models and Other Valuation Methods (b)	(221)	(1,158)	(1,217)	279	862	1,260	(195)
Total	$ 4,830	$ 658	$ 1,031	$ 1,060	$ 862	$ 1,260	$ 9,701

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in 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 are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges

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 operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges 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. In accordance with GAAP, all amounts are presented net of related income taxes.

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

	Power
Beginning Balance December 31, 2003	$ (1,828)
Changes in Fair Value (a)	866
Reclassifications from AOCI to Net Income (b)	1,619
Ending Balance December 31, 2004	$ 657

(a) "Changes in Fair Value" shows 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.
(b) "Reclassifications from AOCI to Net Income" represents 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.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $825 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Management Contracts

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

December 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$157	$511	$220	$75	$189	$733	$307	$73

VaR Associated with Debt Outstanding

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 $120 million and $206 million at December 31, 2004 and 2003, respectively. 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 negatively affect our results of operations or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,128,227	$ 1,593,943	$ 682,049
Sales to AEP Affiliates	47,039	153,568	1,008,444
TOTAL	1,175,266	1,747,511	1,690,493
OPERATING EXPENSES			
Fuel for Electric Generation	59,512	89,389	88,488
Fuel from Affiliates for Electric Generation	101,906	195,527	157,346
Purchased Energy for Resale	206,447	373,388	211,358
Purchased Electricity from AEP Affiliates	6,140	19,097	23,406
Other Operation	301,160	289,232	296,065
Maintenance	63,599	71,361	63,392
Depreciation and Amortization	122,585	197,776	222,191
Taxes Other Than Income Taxes	91,001	92,109	95,500
Income Taxes	26,897	98,092	139,014
TOTAL	979,247	1,425,971	1,296,760
OPERATING INCOME	196,019	321,540	393,733
Carrying Costs on Stranded Cost Recovery	301,644	-	-
Nonoperating Income	45,729	54,172	53,141
Nonoperating Expenses	16,790	17,273	41,910
Nonoperating Income Tax Expense	108,161	7,080	3,152
Interest Charges	123,785	133,812	125,871
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	294,656	217,547	275,941
Extraordinary Loss on Stranded Cost Recovery, Net of Tax	(120,534)	-	-
Cumulative Effect of Accounting Change, Net of Tax	-	122	-
NET INCOME	174,122	217,669	275,941
Gain on Reacquired Preferred Stock	-	-	4
Preferred Stock Dividend Requirements	241	241	241
EARNINGS APPLICABLE TO COMMON STOCK	$ 173,881	$ 217,428	$ 275,704

The common stock of TCC is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 168,888	$ 405,015	$ 826,197	$ -	$ 1,400,100
Redemption of Common Stock	(113,596)	(272,409)			(386,005)
Gain on Reacquired Preferred Stock			4		4
Common Stock Dividends			(115,505)		(115,505)
Preferred Stock Dividends			(241)		(241)
TOTAL					898,353
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $19				(36)	(36)
Minimum Pension Liability, Net of Tax of $39,375				(73,124)	(73,124)
NET INCOME			275,941		275,941
TOTAL COMPREHENSIVE INCOME					202,781
DECEMBER 31, 2002	55,292	132,606	986,396	(73,160)	1,101,134
Common Stock Dividends			(120,801)		(120,801)
Preferred Stock Dividends			(241)		(241)
TOTAL					980,092
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $965				(1,792)	(1,792)
Minimum Pension Liability, Net of Tax of $7,043				13,080	13,080
NET INCOME			217,669		217,669
TOTAL COMPREHENSIVE INCOME					228,957
DECEMBER 31, 2003	55,292	132,606	1,083,023	(61,872)	1,209,049
Common Stock Dividends			(172,000)		(172,000)
Preferred Stock Dividends			(241)		(241)
TOTAL					1,036,808
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,338				2,485	2,485
Minimum Pension Liability, Net of Tax of $31,790				55,228	55,228
NET INCOME			174,122		174,122
TOTAL COMPREHENSIVE INCOME					231,835
DECEMBER 31, 2004	$ 55,292	$ 132,606	$ 1,084,904	$ (4,159)	$ 1,268,643

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Transmission	$ 788,371	$ 767,970
Distribution	1,433,380	1,376,761
General	220,435	221,354
Construction Work in Progress	50,612	58,953
Total	2,492,798	2,425,038
Accumulated Depreciation and Amortization	725,225	695,359
TOTAL - NET	1,767,573	1,729,679
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	1,577	1,302
Bond Defeasance Funds	22,110	-
Other Investments	-	4,639
TOTAL	23,687	5,941
CURRENT ASSETS		
Cash and Cash Equivalents	-	760
Other Cash Deposits	135,132	65,122
Advances to Affiliates	-	60,699
Accounts Receivable:		
Customers	157,431	146,630
Affiliated Companies	67,860	78,484
Accrued Unbilled Revenues	21,589	23,077
Allowance for Uncollectible Accounts	(3,493)	(1,710)
Materials and Supplies	12,288	11,707
Risk Management Assets	14,048	22,051
Margin Deposits	1,891	3,230
Prepayments and Other Current Assets	9,151	10,635
TOTAL	415,897	420,685
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	15,236	3,249
Wholesale Capacity Auction True-Up	559,973	480,000
Unamortized Loss on Reacquired Debt	11,842	9,086
Designated for Securitization	1,361,299	1,289,436
Deferred Debt – Restructuring	11,596	12,015
Other	102,032	127,488
Securitized Transition Assets	642,384	689,399
Long-term Risk Management Assets	9,508	7,627
Prepaid Pension Obligations	109,628	-
Deferred Charges	36,986	51,690
TOTAL	2,860,484	2,669,990
Assets Held for Sale – Texas Generation Plants	628,149	1,028,134
TOTAL ASSETS	$ 5,695,790	$ 5,854,429

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $25 Par Value Per Share:		
Authorized – 12,000,000 Shares		
Outstanding – 2,211,678 Shares	$ 55,292	$ 55,292
Paid-in Capital	132,606	132,606
Retained Earnings	1,084,904	1,083,023
Accumulated Other Comprehensive Loss	(4,159)	(61,872)
Total Common Shareholder's Equity	1,268,643	1,209,049
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Total Shareholders' Equity	1,274,583	1,214,989
Long-term Debt - Nonaffiliated	1,541,552	2,053,974
TOTAL	2,816,135	3,268,963
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	365,742	237,651
Advances from Affiliates	207	-
Accounts Payable:		
General	109,688	90,004
Affiliated Companies	64,045	74,209
Customer Deposits	6,147	1,517
Taxes Accrued	184,014	67,018
Interest Accrued	41,227	43,196
Risk Management Liabilities	8,394	17,888
Obligations Under Capital Leases	412	407
Other	20,115	23,248
TOTAL	799,991	555,138
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,247,111	1,244,912
Long-term Risk Management Liabilities	4,896	2,660
Regulatory Liabilities:		
Asset Removal Costs	102,624	95,415
Deferred Investment Tax Credits	107,743	112,479
Over-recovery of Fuel Costs	211,526	150,026
Retail Clawback	61,384	45,527
Other	76,653	86,706
Obligations Under Capital Leases	468	636
Deferred Credits and Other	17,276	63,833
TOTAL	1,829,681	1,802,194
Liabilities Held for Sale – Texas Generation Plants	249,983	228,134
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,695,790	$ 5,854,429

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 174,122	$ 217,669	$ 275,941
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	122,585	197,776	222,191
Deferred Income Taxes	16,490	19,393	113,655
Deferred Investment Tax Credits	(4,736)	(5,207)	(5,207)
Cumulative Effect of Accounting Change	-	(122)	-
Carrying Costs on Stranded Cost Recovery	(301,644)	-	-
Extraordinary Loss on Stranded Cost Recovery, Net of Tax	120,534	-	-
Mark-to-Market of Risk Management Contracts	2,241	(6,341)	(1,558)
Wholesale Capacity Auction True-up	(79,973)	(218,000)	(262,000)
Pension Contribution	(61,910)	(86)	-
Fuel Recovery	61,500	81,000	16,455
Change in Other Noncurrent Assets	88,025	20,014	(83,183)
Change in Other Noncurrent Liabilities	827	(49,390)	123,800
Changes in Components of Working Capital:			
Accounts Receivable, Net	18,952	15,190	(217,149)
Fuel, Materials and Supplies	(10,641)	15,851	(4,899)
Accounts Payable	9,520	55,772	(6,167)
Taxes Accrued	116,996	42,227	(58,721)
Interest Accrued	(1,969)	(8,009)	27,490
Customer Deposits	4,630	852	(26,078)
Other Current Assets	1,689	(8,165)	402
Other Current Liabilities	(3,128)	(13,046)	13,137
Net Cash Flows From Operating Activities	274,110	357,378	128,109
INVESTING ACTIVITIES			
Construction Expenditures	(121,313)	(131,925)	(132,261)
Change in Other Cash Deposits, Net	(70,010)	19,490	(84,314)
Proceeds from Sale of Assets	429,553	7,455	-
Other	(21,669)	-	143
Net Cash Flows From (Used For) Investing Activities	216,561	(104,980)	(216,432)
FINANCING ACTIVITIES			
Change in Short-term Debt, Net – Affiliated	-	(650,000)	-
Change in Short-term Debt, Net – Nonaffiliated	-	-	650,000
Issuance of Long-term Debt – Nonaffiliated	-	953,136	-
Issuance of Long-term Debt – Affiliated	-	-	797,335
Retirement of Long-term Debt	(380,096)	(247,127)	(639,492)
Change in Advances to/from Affiliates, Net	60,906	(187,410)	(227,566)
Retirement of Common Stock	-	-	(386,005)
Retirement of Preferred Stock	-	(2)	(6)
Dividends Paid on Common Stock	(172,000)	(120,801)	(115,505)
Dividends Paid on Cumulative Preferred Stock	(241)	(241)	(241)
Net Cash Flows (Used For) From Financing Activities	(491,431)	(252,445)	78,520
Net Decrease in Cash and Cash Equivalents	(760)	(47)	(9,803)
Cash and Cash Equivalents at Beginning of Period	760	807	10,610
Cash and Cash Equivalents at End of Period	$ -	$ 760	$ 807

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $117,325,000, $129,491,000 and $93,120,000 and for income taxes was $(1,058,000), $49,630,000 and $95,600,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $348,000.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
SCHEDULE OF PREFERRED STOCK
December 31, 2004 and 2003

						2004	2003
						(in thousands)	
PREFERRED STOCK:							
$100 Par Value Per Share - Authorized 3,035,000 shares							
Series	Call Price December 31, 2004	Number of Shares Redeemed Year Ended December 31,			Shares Outstanding December 31, 2004		
		2004	2003	2002			
Not Subject to Mandatory Redemption							
4.00%	$105.75	5	11	100	41,922	$ 4,192	$ 4,192
4.20%	103.75	-	-	-	17,476	1,748	1,748
Total						$ 5,940	$ 5,940

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
December 31, 2004 and 2003

	2004	2003
LONG-TERM DEBT:	(in thousands)	
First Mortgage Bonds	$ 84,344	$ 117,939
Securitization Bonds	697,193	745,680
Senior Unsecured Notes	797,863	797,532
Installment Purchase Contracts	327,894	489,585
Note Payable to Trust (a)	-	140,889
Less Portion Due Within One Year	(365,742)	(237,651)
Long-term Debt Excluding Portion Due Within One Year	$ 1,541,552	$ 2,053,974

(a) See "Trust Preferred Securities" section of Note 16 for discussion of Note Payable to Trust.

There are certain limitations on establishing liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.250	2004 – October 1	$ -	$ 27,400
7.125	2008 – February 1	18,581	18,581
6.625	2005 – July 1	65,763	71,958
Total		$ 84,344	$ 117,939

First Mortgage Bonds are secured by a first mortgage lien on Electric Utility Plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually. In 2004, the First Mortgage Bonds were defeased in connection with the sale of several generation plants.

Securitization Bonds outstanding were as follows:

% Rate	Final Payment Date	Maturity Date	2004	2003
			(in thousands)	
3.54	1/15/2005	1/15/2007	$ 29,386	$ 77,937
5.01	1/15/2008	1/15/2010	154,507	154,507
5.56	1/15/2010	1/15/2012	107,094	107,094
5.96	7/15/2013	7/15/2015	214,927	214,927
6.25	1/15/2016	1/15/2017	191,857	191,857
Unamortized Discount			(578)	(642)
Total			$ 697,193	$ 745,680

The Securitization Bonds mature at different times through 2017 and have a weighted average interest rate of 5.7 percent at December 31, 2004.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
5.500	2013 – February 15	$ 275,000	$ 275,000
6.650	2033 – February 15	275,000	275,000
3.000	2005 – February 15	150,000	150,000
(a)	2005 – February 15	100,000	100,000
Unamortized Discount		(2,137)	(2,468)
Total		$ 797,863	$ 797,532

(a) A floating interest rate is determined quarterly. The rate on December 31, 2004 was 3.54%.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2004	2003
			(in thousands)	
Matagorda County Navigation District, Texas	6.000	2028 – July 1	$ 120,265	$ 120,265
	6.125	2030 – May 1	60,000	60,000
	2.150	2030 – May 1 (a)	-	111,700
	4.550	2029 – November 1 (b)	100,635	100,635
	2.350	2030 – May 1 (a)	-	50,000
Guadalupe-Blanco River Authority District, Texas	(c)	2015 – November 1	40,890	40,890
Red River Authority of Texas	6.00	2020 – June 1	6,330	6,330
	Unamortized Discount		(226)	(235)
	Total		$ 327,894	$ 489,585

(a) These bonds were reissued in February 2005.

(b) Installment Purchase Contract provides for bonds to be tendered in 2006 for 4.55% series. Therefore, this installment purchase contract has been classified for payment in 2006.

(c) A floating interest rate is determined daily. The rate on December 31, 2004 and 2003 was 2.15% and 1.30%, respectively.

Under the terms of the installment purchase contracts, we are required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments range from monthly to semi-annually.

Note Payable to Trust was outstanding as follows:

% Rate	Due	2004	2003
		(in thousands)	
8.00	2037 – April 30	$ -	$ 140,889

See "Trust Preferred Securities" in Note 16 for discussion of Notes Payable to Trust.

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ 365,742
2006	152,900
2007	52,730
2008	68,688
2009	53,627
Later Years	1,216,548
Total Principal Amount	1,910,235
Unamortized Discount	(2,941)
Total	$ 1,907,294

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to TCC's consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to TCC. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
AEP Texas Central Company:

We have audited the accompanying consolidated balance sheets of AEP Texas Central Company and subsidiary as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of AEP Texas Central Company and subsidiary 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.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

AEP TEXAS NORTH COMPANY

AEP TEXAS NORTH COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF OPERATIONS DATA					
Operating Revenues	$ 492,145	$ 465,946	$ 450,740	$ 556,458	$ 571,064
Operating Income	61,246	68,027	7,871	33,390	52,341
Interest Charges	21,985	22,049	20,845	23,275	23,216
Income (Loss) Before Extraordinary Loss and Cumulative Effect of Accounting Change	47,659	55,663	(13,677)	12,310	27,450
Extraordinary Loss, Net of Tax	-	(177)	-	-	-
Cumulative Effect of Accounting Change, Net of Tax	-	3,071	-	-	-
Net Income (Loss)	47,659	58,557	(13,677)	12,310	27,450
BALANCE SHEETS DATA					
Electric Utility Plant	$ 1,182,327	$ 1,233,427	$ 1,201,747	$ 1,260,872	$ 1,229,339
Accumulated Depreciation and Amortization	405,933	460,513	446,818	475,036	447,802
Net Electric Utility Plant	$ 776,394	$ 772,914	$ 754,929	$ 785,836	$ 781,537
Total Assets	$ 1,051,529	$ 989,009	$ 952,149	$ 936,001	$ 1,154,743
Common Shareholder's Equity	310,421	238,275	180,744	245,535	262,153
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357	2,367	2,367	2,367
Long-term Debt (a)	314,357	356,754	132,500	255,967	255,843
Obligations Under Capital Leases (a)	534	473	-	-	-

(a) Including portion due within one year.

AEP TEXAS NORTH COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

TNC is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power in west and central Texas. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. We also sell electric power at wholesale to other utilities, municipalities, rural electric cooperatives and retail electric providers (REPs) in Texas.

Power pool members are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

2004 Compared to 2003

Net Income decreased $11 million for 2004 primarily driven by lower margins from risk management activities, a provision for potential loss on fuel disputes and a 2003 Cumulative Effect of Accounting Change.

Operating Income

Operating Income decreased $7 million primarily due to:

- A $31 million net increase in fuel and purchased power expenses. KWHs purchased increased 17% while the average cost per KWH purchased decreased 23%. KWH generation increased 1% while the generation cost per KWH increased 20% primarily due to a one-time provision for possible loss in fuel disputes.
- A $5 million decrease in margins from risk management activities.
- A $5 million decrease in other electric revenue, primarily Qualified Scheduling Entity (QSE) fees and miscellaneous service revenue.

- A $3 million increase in Depreciation and Amortization expenses primarily due to the 2003 amortization credit adjustment for excess earnings accruals related to a final court determination (see "Texas Restructuring" and "Unrefunded Excess Earnings" section of Note 6).
- A $2 million increase in Taxes Other Than Income Taxes primarily due to higher accrued property taxes attributable to changes in property values, property tax rates, net fixed asset increases, accrual update adjustments and timing of prior period true-ups.
- A $2 million decrease in Reliability Must Run (RMR) revenues from ERCOT, which include a fuel recovery increase of $2 million and a fixed cost decrease of $4 million. We will no longer have RMR revenues after 2004. In 2004, RMR revenues totaled $51 million of which $9 million was for reimbursement of fixed cost.
- A $2 million increase in Other Operation expenses primarily due to higher ERCOT related transmission expense.
- A $2 million increase in Maintenance expenses primarily due to overhead line and pole inspection expenses.

The decrease in Operating Income was partially offset by:

- A $12 million increase in off-system sales, including those to REPs, primarily due to higher KWH sales of 2%.
- A $10 million increase in revenues due to a decrease in provision for rate refunds primarily due to fuel reconciliation issues (see "TNC Fuel Reconciliations" section of Note 4).
- A $10 million increase in transmission revenue primarily due to prior year adjustments recorded in 2004 for affiliated open access transmission tariff and ancillary services resulting from revised data received from ERCOT for the years 2001-2003.
- A $7 million increase in revenues from ERCOT for various services, including balancing energy and prior year adjustments made by ERCOT.
- A $7 million decrease in Income Taxes. See Income Taxes section below for further discussion.

Other Impacts on Earnings

Nonoperating Income decreased $6 million primarily as a result of a $3 million decrease in nonutility revenue associated with energy-related construction projects for third parties and a decrease of $3 million related to risk management activities.

Nonoperating Expenses decreased $4 million primarily due to lower nonutility expenses associated with energy-related construction projects for third parties.

Income Taxes

The effective tax rates for 2004 and 2003 were 32.1% and 35.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35.0% is due to permanent differences, amortization of investment tax credits, consolidated tax savings, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to an increase in favorable federal income tax adjustments.

Extraordinary Loss

Extraordinary Loss in 2003 resulted from the cessation of SFAS 71 accounting for wholesale generation assets due to the FERC settlement case (see "Extraordinary Item" in Note 2).

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change is due to a one-time after tax impact of adopting SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003 (see "Asset Retirement Obligations" in Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

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)	$ 37.6	$ 8.1	$ -	$ 269.4	$ 315.1
Capital Lease Obligations (b)	0.2	0.2	0.1	0.1	0.6
Noncancelable Operating Leases (b)	2.2	3.4	2.8	3.0	11.4
Energy and Capacity Purchase Contracts (c)	19.9	39.9	36.2	83.8	179.8
Total	$ 59.9	$ 51.6	$ 39.1	$ 356.3	$ 506.9

(a) See Schedule of Long-term Debt. Represents principal only excluding interest.
(b) See Note 15.
(c) Represents contractual cash flows of energy and capacity purchase contracts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2004 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
Transmission Facilities for Third Parties (a)	$ 20.2	$ 34.0	$ 6.4	$ -	$ 60.6

(a) 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.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effects on us.

MTM Risk Management Contract Net Assets

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

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

Total MTM Risk Management Contract Net Assets at December 31, 2003	$ 4,620
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(1,915)
Fair Value of New Contracts When Entered During the Period (b)	508
Net Option Premiums Paid/(Received) (c)	(53)
Change in Fair Value Due to Valuation Methodology Changes (d)	45
Changes in Fair Value of Risk Management Contracts (e)	987
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	4,192
Net Cash Flow Hedge Contracts (g)	245
Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 4,437

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

(b) "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 that were 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, 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 Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

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

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 4,368	$ 1,703	$ 6,071
Noncurrent Assets	4,107	3	4,110
Total MTM Derivative Contract Assets	8,475	1,706	10,181
Current Liabilities	(2,281)	(1,347)	(3,628)
Noncurrent Liabilities	(2,002)	(114)	(2,116)
Total MTM Derivative Contract Liabilities	(4,283)	(1,461)	(5,744)
Total MTM Derivative Contract Net Assets	$ 4,192	$ 245	$ 4,437

(a) Does not include Cash Flow 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 Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of December 31, 2004
(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (553)	$ (20)	$ 278	$ -	$ -	$ -	$ (295)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	2,736	805	693	338	-	-	4,572
Prices Based on Models and Other Valuation Methods (b)	(96)	(502)	(526)	121	373	545	(85)
Total	$ 2,087	$ 283	$ 445	$ 459	$ 373	$ 545	$ 4,192

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in 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 are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges.

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 operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges 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. In accordance with GAAP, all amounts are presented net of related income taxes.

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

		Power
Beginning Balance December 31, 2003	$	(601)
Changes in Fair Value (a)		373
Reclassifications from AOCI to Net Income (b)		513
Ending Balance December 31, 2004	$	285

(a) "Changes in Fair Value" shows 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.
(b) "Reclassifications from AOCI to Net Income" represents 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.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $357 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

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

December 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$68	$221	$95	$33	$76	$294	$123	$29

VaR Associated with Debt Outstanding

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 $13 million and $33 million at December 31, 2004 and 2003, respectively. 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 negatively affect our results of operations or financial position.

AEP TEXAS NORTH COMPANY
STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 440,465	$ 410,793	$ 210,315
Sales to AEP Affiliates	51,680	55,153	240,425
TOTAL	492,145	465,946	450,740
OPERATING EXPENSES			
Fuel for Electric Generation	54,442	39,082	36,081
Fuel from Affiliates for Electric Generation	46,496	44,197	64,385
Purchased Energy for Resale	134,774	87,006	80,391
Purchased Electricity from AEP Affiliates	5,211	39,409	37,582
Other Operation	87,046	85,263	104,960
Asset Impairments	-	-	42,898
Maintenance	20,602	18,961	22,295
Depreciation and Amortization	39,025	36,242	43,620
Taxes Other Than Income Taxes	22,630	20,570	22,471
Income Taxes Expense (Credit)	20,673	27,189	(11,814)
TOTAL	430,899	397,919	442,869
OPERATING INCOME	61,246	68,027	7,871
Nonoperating Income	62,036	68,451	53,884
Nonoperating Expenses	51,802	55,692	54,876
Nonoperating Income Tax Expense (Credit)	1,836	3,074	(289)
Interest Charges	21,985	22,049	20,845
Income (Loss) Before Extraordinary Loss and Cumulative Effect of Accounting Change	47,659	55,663	(13,677)
Extraordinary Loss, Net of Tax	-	(177)	-
Cumulative Effect of Accounting Change, Net of Tax	-	3,071	-
NET INCOME (LOSS)	47,659	58,557	(13,677)
Gain on Reacquired Preferred Stock	-	3	-
Preferred Stock Dividend Requirements	103	104	104
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 47,556	$ 58,456	$ (13,781)

The common stock of TNC is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 137,214	$ 2,351	$ 105,970	$ -	$ 245,535
Common Stock Dividends			(20,247)		(20,247)
Preferred Stock Dividends			(104)		(104)
TOTAL					225,184
COMPREHENSIVE LOSS					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $8				(15)	(15)
Minimum Pension Liability, Net of Tax of $16,557				(30,748)	(30,748)
NET LOSS			(13,677)		(13,677)
TOTAL COMPREHENSIVE LOSS					(44,440)
DECEMBER 31, 2002	137,214	2,351	71,942	(30,763)	180,744
Common Stock Dividends			(4,970)		(4,970)
Preferred Stock Dividends			(104)		(104)
Gain on Reacquired Preferred Stock			3		3
TOTAL					175,673
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $316				(586)	(586)
Minimum Pension Liability, Net of Tax of $2,498				4,631	4,631
NET INCOME			58,557		58,557
TOTAL COMPREHENSIVE INCOME					62,602
DECEMBER 31, 2003	137,214	2,351	125,428	(26,718)	238,275
Common Stock Dividends			(2,000)		(2,000)
Preferred Stock Dividends			(103)		(103)
TOTAL					236,172
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $477				886	886
Minimum Pension Liability, Net of Tax of $13,841				25,704	25,704
NET INCOME			47,659		47,659
TOTAL COMPREHENSIVE INCOME					74,249
DECEMBER 31, 2004	$ 137,214	$ 2,351	$ 170,984	$ (128)	$ 310,421

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 287,212	$ 360,463
Transmission	281,359	268,695
Distribution	474,961	456,278
General	115,174	117,792
Construction Work in Progress	23,621	30,199
Total	1,182,327	1,233,427
Accumulated Depreciation and Amortization	405,933	460,513
TOTAL - NET	776,394	772,914
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	1,407	1,286
CURRENT ASSETS		
Other Cash Deposits	2,308	2,863
Advances to Affiliates	51,504	41,593
Accounts Receivable:		
Customers	90,109	56,670
Affiliated Companies	21,474	28,910
Accrued Unbilled Revenues	3,789	4,871
Miscellaneous	-	3,411
Allowance for Uncollectible Accounts	(787)	(175)
Unbilled Construction Costs	22,065	16,943
Fuel Inventory	3,148	10,925
Materials and Supplies	8,273	8,866
Risk Management Assets	6,071	10,340
Margin Deposits	818	1,285
Prepayments and Other	1,053	1,834
TOTAL	209,825	188,336
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Under Recovery of Fuel Costs	-	6,180
Deferred Debt – Restructuring	6,093	6,579
Unamortized Loss on Reacquired Debt	2,147	3,929
Other	3,783	3,332
Long-term Risk Management Assets	4,110	3,106
Prepaid Pension Obligations	44,911	-
Deferred Charges	2,859	3,347
TOTAL	63,903	26,473
TOTAL ASSETS	$ 1,051,529	$ 989,009

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2004 and 2003

	2004	2003
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - $25 Par Value per share:		
Authorized – 7,800,000 Shares		
Outstanding – 5,488,560 Shares	$ 137,214	$ 137,214
Paid-in Capital	2,351	2,351
Retained Earnings	170,984	125,428
Accumulated Other Comprehensive Income (Loss)	(128)	(26,718)
Total Common Shareholder's Equity	310,421	238,275
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357
Total Shareholders' Equity	312,778	240,632
Long-term Debt – Nonaffiliated	276,748	314,249
TOTAL	589,526	554,881
CURRENT LIABILITIES		
Long-term Debt Due Within One Year – Nonaffiliated	37,609	42,505
Accounts Payable:		
General	22,444	28,190
Affiliated Companies	52,801	40,601
Customer Deposits	1,020	161
Taxes Accrued	37,269	22,877
Interest Accrued	5,044	6,038
Risk Management Liabilities	3,628	8,658
Obligations Under Capital Leases	220	203
Other	9,628	9,419
TOTAL	169,663	158,652
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	138,465	113,019
Long-term Risk Management Liabilities	2,116	1,094
Regulatory Liabilities:		
Asset Removal Costs	81,143	76,740
Deferred Investment Tax Credits	18,698	19,990
Over-recovery of Fuel Costs	3,920	-
Retail Clawback	13,924	11,804
Excess Earnings	13,270	14,262
SFAS 109 Regulatory Liability, Net	8,500	13,655
Other	1,319	1,826
Obligations Under Capital Leases	314	270
Deferred Credits and Other	10,671	22,816
TOTAL	292,340	275,476
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 1,051,529	$ 989,009

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income (Loss)	$ 47,659	$ 58,557	$ (13,677)
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	39,025	36,242	43,620
Extraordinary Item	-	177	-
Asset Impairments and Investment Value Losses	-	-	42,898
Deferred Income Taxes	4,236	(3,493)	(12,275)
Deferred Investment Tax Credits	(1,292)	(1,521)	(1,271)
Cumulative Effect of Accounting Change	-	(3,071)	-
Mark-to-Market of Risk Management Contracts	428	(2,558)	(1,127)
Over/Under Fuel Recovery	10,100	15,960	14,169
Pension Contribution	(21,172)	(410)	-
Change in Other Noncurrent Assets	(8,368)	6,081	(15,719)
Change in Other Noncurrent Liabilities	13,521	(5,069)	14,985
Changes in Components of Working Capital:			
Accounts Receivable, Net	(18,779)	14,393	(80,900)
Fuel, Materials and Supplies	8,370	2,460	(2,754)
Accounts Payable	6,454	(40,140)	63,761
Taxes Accrued	14,392	19,180	(13,661)
Customer Deposits	859	45	(4,075)
Interest Accrued	(994)	3,261	(1,986)
Other Current Assets	(4,834)	(15,035)	(1,209)
Other Current Liabilities	225	(7,791)	7,590
Net Cash Flows From Operating Activities	89,830	77,268	38,369
INVESTING ACTIVITIES			
Construction Expenditures	(36,375)	(46,683)	(43,563)
Change in Other Cash Deposits, Net	555	(1,706)	(764)
Proceeds from Sale of Assets	510	688	-
Other	-	-	150
Net Cash Flows Used For Investing Activities	(35,310)	(47,701)	(44,177)
FINANCING ACTIVITIES			
Change in Short-term Debt, Net – Affiliated	-	(125,000)	125,000
Issuance of Long-term Debt	-	222,455	-
Retirement of Long-term Debt	(42,506)	-	(130,799)
Retirement of Preferred Stock	-	(10)	-
Changes in Advances to/from Affiliates, Net	(9,911)	(122,000)	29,959
Dividends Paid on Common Stock	(2,000)	(4,970)	(20,247)
Dividends Paid on Cumulative Preferred Stock	(103)	(104)	(104)
Net Cash Flows From (Used For) Financing Activities	(54,520)	(29,629)	3,809
Net Decrease in Cash and Cash Equivalents	-	(62)	(1,999)
Cash and Cash Equivalents at Beginning of Period	-	62	2,061
Cash and Cash Equivalents at End of Period	$ -	$ -	$ 62

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $20,860,000, $16,384,000 and $19,934,000 and for income taxes was $6,905,000, $16,081,000 and $15,544,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $282,000.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
SCHEDULE OF PREFERRED STOCK
December 31, 2004 and 2003

	2004	2003
	(in thousands)	

PREFERRED STOCK:
$100 Par Value Per Share - Authorized 810,000 shares

Series	Call Price December 31, 2004	Number of Shares Redeemed Year Ended December 31,			Shares Outstanding December 31, 2004	2004	2003
		2004	2003	2002			
Not Subject to Mandatory Redemption:							
4.40%	$107	4	102	-	23,566	$ 2,357	$ 2,357

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
SCHEDULE OF LONG-TERM DEBT
December 31, 2004 and 2003

		2004		2003
LONG-TERM DEBT:		(in thousands)		
First Mortgage Bonds	$	45,752	$	88,236
Installment Purchase Contracts		44,310		44,310
Senior Unsecured Notes		224,295		224,208
Less Portion Due Within One Year		(37,609)		(42,505)
Long-term Debt Excluding Portion Due Within One Year	$	276,748	$	314,249

There are certain limitations on establishing liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

% Rate	Due		2004		2003
			(in thousands)		
7.000	2004 – October 1	$	-	$	18,469
6.125	2004 – February 1		-		24,036
6.375	2005 – October 1		37,609		37,609
7.750	2007 – June 1		8,151		8,151
Unamortized Discount			(8)		(29)
Total		$	45,752	$	88,236

First Mortgage Bonds are secured by a first mortgage lien on Electric Utility Plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Installment Purchase Contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due		2004		2003
				(in thousands)		
Red River Authority of Texas	6.000	2020 – June 1	$	44,310	$	44,310

Under the terms of the Installment Purchase Contracts, we are required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due		2004		2003
			(in thousands)		
5.500	2013 – March 1	$	225,000	$	225,000
Unamortized Discount			(705)		(792)
Total		$	224,295	$	224,208

At December 31, 2004, future annual Long-term Debt payments are as follows:

		Amount
		(in thousands)
2005	$	37,609
2006		-
2007		8,151
2008		-
2009		-
Later Years		269,310
Total Principal Amount		315,070
Unamortized Discount		(713)
Total	$	314,357

AEP TEXAS NORTH COMPANY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to TNC's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to TNC. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
AEP Texas North Company:

We have audited the accompanying balance sheets of AEP Texas North Company as of December 31, 2004 and 2003, and the related statements of operations, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Texas North Company as of December 31, 2004 and 2003, and the results of its operations and its 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.

As discussed in Note 2 to the financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," effective January 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 1,948,182	$ 1,957,358	$ 1,814,470	$ 1,784,259	$ 1,759,253
Operating Income	244,010	318,811	302,063	274,986	201,154
Interest Charges	98,947	115,202	116,677	120,036	148,000
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	153,115	202,783	205,492	161,818	64,906
Extraordinary Gain	-	-	-	-	8,938
Cumulative Effect of Accounting Changes, Net of Tax	-	77,257	-	-	-
Net Income	153,115	280,040	205,492	161,818	73,844
BALANCE SHEETS DATA					
Electric Utility Plant	$ 6,529,630	$ 6,140,931	$ 5,895,303	$ 5,664,657	$ 5,418,278
Accumulated Depreciation and Amortization	2,443,218	2,321,360	2,330,012	2,207,072	2,103,471
Net Electric Utility Plant	$ 4,086,412	$ 3,819,571	$ 3,565,291	$ 3,457,585	$ 3,314,807
Total Assets	$ 5,239,918	$ 4,977,011	$ 4,722,442	$ 4,572,194	$ 6,657,920
Common Shareholder's Equity	1,409,718	1,336,987	1,166,057	1,126,701	1,096,260
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784	17,790	17,790	17,790
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	-	5,360	10,860	10,860	10,860
Long-term Debt (a)	1,784,598	1,864,081	1,893,861	1,556,559	1,605,818
Obligations Under Capital Leases (a)	19,878	25,352	33,589	46,285	63,160

(a) Including portion due within one year.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

APCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 934,000 retail customers in our service territory in southwestern Virginia and southern West Virginia. We consolidate Cedar Coal Company, Central Appalachian Coal Company and Southern Appalachian Coal Company, our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs. We had a new all time peak demand in December 2004, therefore we will have an increase in our MLR percentage in 2005.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated 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 via the AEP Power Pool, discussed above.

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 the new environment. We are confident in our ability to participate successfully in the PJM market.

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

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

Net Income for 2004 decreased $127 million over the prior year period largely due to the Cumulative Effect of Accounting Changes of $77 million recorded in 2003. See "Cumulative Effect of Accounting Changes" in Note 2 for further information. Net Income was also affected by an increase in expenses in the current year, primarily in Maintenance and Other Operation, coupled with a decrease in revenue. The unfavorable impacts on Net Income were partially offset by decreased Income Taxes.

Net Income for 2003 increased $75 million over the prior year period primarily due to the Cumulative Effect of Accounting Changes of $77 million recorded in 2003. Net Income was also affected by an increase in both Electric Generation, Transmission and Distribution and Sales to AEP Affiliates revenues, offset by an increase in purchased power and Fuel for Electric Generation expenses.

2004 Compared to 2003

Operating Income

Operating Income for 2004 decreased by $75 million from 2003 primarily due to:

- A $40 million increase in Maintenance expense primarily caused by boiler plant maintenance at Amos, Clinch River, Glen Lyn, Mountaineer and Kanawha River plants in 2004.
- A $24 million increase in Other Operation expense due to increased administrative and support expenses, increased insurance premiums and increased removal costs in 2004. These increases were partially offset by reduced labor costs and increased gains recorded on the dispositions of SO_2 emission allowances in 2004.
- An $18 million increase in Depreciation and Amortization related to a greater depreciable base in 2004 including the addition of capitalized software costs partially offset by reduced amortization of Virginia's transition generation regulatory assets.
- A net $10 million increase in fuel and purchased energy expenses. Purchased energy increased $45 million due to increases in volume and price, offset by a $35 million decrease in Fuel for Electric Generation expense. The decrease in Fuel for Electric Generation expense results from accruing less fuel expense in order to match fuel revenues billed to ratepayers (See "Deferred Fuel Costs" section in Note 1).
- A $6 million decrease in Sales to AEP Affiliates resulting from decreased power available due mainly to planned plant outages.
- A $3 million decrease in Electric Generation, Transmission and Distribution revenues related to a decrease in off-system sales, including PJM transactions, offset by increased retail revenues resulting from a 28% increase in cooling degree days in the current year.

The decrease in Operating Income for 2004 was partially offset by:

- A $29 million decrease in Income Taxes. See Income Taxes section below for further discussion.

Other Impacts on Earnings

Nonoperating Income (Loss) increased $16 million in 2004 compared to 2003 primarily due to favorable results from risk management activities.

Nonoperating Income Tax Credit decreased $8 million in 2004 compared to 2003. See Income Taxes section below for further discussion.

Interest Charges decreased $16 million in 2004 compared to 2003 due to reduced interest rates from refinancing higher cost debt and increased construction-related capitalized interest.

Income Taxes

The effective tax rates for 2004 and 2003 were 35.7% and 34.2%, 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, consolidated tax savings from Parent, amortization of investment tax credits, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes of $77 million in 2003 was due to the implementation of SFAS 143 and EITF 02-3 (see "Cumulative Effect" section in Note 2).

<u>2003 Compared to 2002</u>

Operating Income

Operating Income for 2003 increased by $17 million from 2002 primarily due to:

- A $107 million increase in Electric Generation, Transmission and Distribution revenues related to increases in off-system sales and transmission revenues reflecting an increase in the volume of AEP Power Pool transactions as well as our relative share based on a higher MLR due to a new peak demand in January 2003.
- A $36 million increase in Sales to AEP Affiliates due to strong wholesale sales by the AEP Power Pool.
- A $24 million decrease in Other Operation expense primarily related to severance expenses of $13 million incurred in 2002 caused by the SEI initiative (see Note 9). In addition, reduced employee related expenses and insurance premiums occurred in 2003. These decreases were partially offset by an increase in transmission equalization charges due to the increase in APCo's MLR.
- A $14 million decrease in Depreciation and Amortization expense primarily due to reduced amortization of generation-related regulatory assets due to the return to SFAS 71 for the West Virginia jurisdiction in the first quarter of 2003 (see "West Virginia Restructuring" section of Note 6).

The increase in Operating Income for 2003 was partially offset by:

- A net $150 million increase in purchased power expenses and fuel expense resulted from a $62 million increase in capacity charges caused by the increase in our MLR as described above, the increase in our relative share of the AEP Power Pool expenses and increased generation. The increase in Fuel for Electric Generation expense resulted from accruing more fuel expense in order to match fuel revenues billed to ratepayers (See "Deferred Fuel Costs" section of Note 1).
- A $13 million increase in Maintenance expense primarily due to increased maintenance of overhead lines resulting from severe storm damage in the first quarter of 2003 and increased overhead line maintenance throughout the year.

Other Impacts on Earnings

Nonoperating Income (Loss) decreased $36 million in 2003 compared to 2002 primarily due to unfavorable results from risk management activities.

Nonoperating Income Tax Credit increased $12 million in 2003 compared to 2002. See Income Taxes section below for further discussion.

Income Taxes

The effective tax rates for 2003 and 2002 were 34.2% and 35.1%, 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, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes of $77 million in 2003 was due to the implementation of SFAS 143 and EITF 02-3 (see "Cumulative Effect" section in Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A-
Senior Unsecured Debt	Baa2	BBB	BBB+

Cash Flow

Cash flows for 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(in thousands)	
Cash and cash equivalents at beginning of period	$ 4,561	$ 4,133	$ 7,412
Cash flows from (used for):			
Operating activities	414,074	461,276	280,709
Investing activities	(408,395)	(327,776)	(269,376)
Financing activities	(9,704)	(133,072)	(14,612)
Net increase (decrease) in cash and cash equivalents	(4,025)	428	(3,279)
Cash and cash equivalents at end of period	$ 536	$ 4,561	$ $4,133

Operating Activities

Our net cash flows from operating activities were $414 million in 2004. We produced income of $153 million during the period and noncash expense items of $194 million for Depreciation and Amortization and $48 million for Deferred Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had one significant item; an increase in Taxes Accrued of $40 million. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP 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 extensions are filed.

Our net cash flows from operating activities were $461 million in 2003. We produced income of $280 million during the period and had a noncash expense item of $176 million for Depreciation and Amortization as a result of increased amortization for the net generation-related regulatory assets related to WV jurisdiction that were assigned to the distribution business and are being recovered through rates. Other noncash expense items include $77 million for the Cumulative Effect of Accounting Changes due to the implementation of SFAS 143 & EITF 02-3 and $56 million of Mark-to-Market of Risk Management Contracts as a result of increased gains from risk management activities. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had no significant items in 2003.

Our net cash flows from operating activities were $281 million in 2002. We produced income of $205 million during the period and noncash expense items of $189 million for Depreciation and Amortization and an increase in Other Noncurrent Assets of $50 million related to an increase in regulatory assets and deferred charges. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had one significant item; an increase in Accounts Receivable of $83 million due to timing differences with AEP Energy Services and AEPSC.

Investing Activities

Cash flows used for investing activities during 2004, 2003, and 2002 primarily reflect our construction expenditures of $452 million, $289 million, and $277 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. In 2004, capital projects for Transmission expenditures are primarily related to the Jackson Ferry-Wyoming 765 KV line. Environmental upgrades include the installation of selective catalytic reduction (SCR) equipment on Amos Unit 2 and the flue gas desulfurization (FGD) project at the Mountaineer Plant.

Financing Activities

In 2004, we issued Senior Unsecured Notes of $125 million with a floating interest rate. We reacquired First Mortgage Bonds, Senior Unsecured Notes, and Installment Purchase Contracts of $116 million, $50 million, and $40 million, respectively, at higher stated interest rates. We also increased borrowings from the Utility Money Pool of $128 million and paid common dividends of $50 million.

In 2003, we issued two series of Senior Unsecured Notes, each in the amount of $200 million that were used to call First Mortgage Bonds, Senior Unsecured Notes and fund maturities. Additionally, we incurred obligations of $188 million in Installment Purchase Contracts to redeem higher cost Installment Purchase Contracts. In addition, we had increased borrowings from the Utility Money Pool of $44 million and paid common dividends of $128 million.

In 2002, we issued two series of Senior Unsecured Notes, one for $450 million at 4.8% and the other for $200 million at 4.3%. We reacquired First Mortgage Bonds and Junior Debentures of $150 million and $165 million, respectively. We also reduced short-term borrowing from the Utility Money Pool by $253 million and paid common dividends of $93 million.

In January 2005, we issued Senior Unsecured Notes in the amount of $200 million at a rate of 4.95%.

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)	$ 530.0	$ 442.5	$ 350.0	$ 467.0	$ 1,789.5
Advances from Affiliates (b)	211.1	-	-	-	211.1
Capital Lease Obligations (c)	8.0	9.7	4.1	1.1	22.9
Noncancelable Operating Leases (c)	7.1	10.7	6.6	6.4	30.8
Fuel Purchase Contracts (d)	480.2	442.7	101.7	45.0	1,069.6
Energy and Capacity Purchase Contracts (e)	22.4	33.1	-	-	55.5
Total	$ 1,258.8	$ 938.7	$ 462.4	$ 519.5	$ 3,179.4

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.
(b) Represents short-term borrowings from The Utility Money Pool.
(c) See Note 15.
(d) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(e) Represents contractual cash flows of energy and capacity purchase contracts.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

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

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

Total MTM Risk Management Contract Net Assets at December 31, 2003	$ 68,066
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(34,461)
Fair Value of New Contracts When Entered During the Period (b)	2,520
Net Option Premiums Paid/(Received) (c)	(452)
Change in Fair Value Due to Valuation Methodology Changes (d)	835
Changes in Fair Value of Risk Management Contracts (e)	8,492
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	9,124
Total MTM Risk Management Contract Net Assets	54,124
Net Cash Flow and Fair Value Hedge Contracts (g)	(13,817)
DETM Assignment (h)	(23,736)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 16,571

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

(b) "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 that were 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, 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 liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

(h) See "AEP East Companies" in Note 17.

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

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 66,911	$ 14,900	$ -	$ 81,811
Noncurrent Assets	81,226	19	-	81,245
Total MTM Derivative Contract Assets	148,137	14,919	-	163,056
Current Liabilities	(50,214)	(27,315)	(11,607)	(89,136)
Noncurrent Liabilities	(43,799)	(1,421)	(12,129)	(57,349)
Total MTM Derivative Contract Liabilities	(94,013)	(28,736)	(23,736)	(146,485)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 54,124	$ (13,817)	$ (23,736)	$ 16,571

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "AEP East Companies" in Note 17.
(c) 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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 Fair Value of Contracts as of December 31, 2004 (in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (4,720)	$ (171)	$ 2,373	$ -	$ -	$ -	$ (2,518)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	22,364	9,087	8,016	2,879	-	-	42,346
Prices Based on Models and Other Valuation Methods (b)	(947)	(951)	(992)	4,377	6,240	6,569	14,296
Total	$ 16,697	$ 7,965	$ 9,397	$ 7,256	$ 6,240	$ 6,569	$ 54,124

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in 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 are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow and Fair Value Hedges.

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 operations. We monitor these risks on our future operations and may employ various commodity instruments 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 table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges 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. In accordance with GAAP, all amounts are presented net of related income taxes.

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

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance December 31, 2003	$ 359	$ (183)	$ (1,745)	$ (1,569)
Changes in Fair Value (a)	3,894	-	(10,163)	(6,269)
Reclassifications from AOCI to Net Income (b)	(1,831)	7	338	(1,486)
Ending Balance December 31, 2004	$ 2,422	$ (176)	$ (11,570)	$ (9,324)

(a) "Changes in Fair Value" shows 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.

(b) "Reclassifications from AOCI to Net Income" represents 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.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,876 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

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

December 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$577	$1,883	$812	$277	$596	$2,314	$969	$230

VaR Associated with Debt Outstanding

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 $99 million and $102 million at December 31, 2004 and 2003, respectively. 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 negatively affect our results of operations or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,731,619	$ 1,734,565	$ 1,627,993
Sales to AEP Affiliates	216,563	222,793	186,477
TOTAL	1,948,182	1,957,358	1,814,470
OPERATING EXPENSES			
Fuel for Electric Generation	420,187	454,901	430,963
Purchased Energy for Resale	91,173	66,084	57,091
Purchased Electricity from AEP Affiliates	370,953	351,210	234,597
Other Operation	269,349	245,308	269,426
Maintenance	175,283	135,596	122,209
Depreciation and Amortization	193,525	175,772	189,335
Taxes Other Than Income Taxes	92,624	90,087	95,249
Income Taxes	91,078	119,589	113,537
TOTAL	1,704,172	1,638,547	1,512,407
OPERATING INCOME	244,010	318,811	302,063
Nonoperating Income (Loss)	10,742	(5,661)	30,020
Nonoperating Expenses	8,657	9,534	12,525
Nonoperating Income Tax Credit	5,967	14,369	2,611
Interest Charges	98,947	115,202	116,677
Income Before Cumulative Effect of Accounting Changes	153,115	202,783	205,492
Cumulative Effect of Accounting Changes, Net of Tax	-	77,257	-
NET INCOME	153,115	280,040	205,492
Preferred Stock Dividend Requirements, Including Capital Stock Expense	3,215	3,495	2,898
EARNINGS APPLICABLE TO COMMON STOCK	$ 149,900	$ 276,545	$ 202,594

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 260,458	$ 715,786	$ 150,797	$ (340)	$ 1,126,701
Common Stock Dividends			(92,952)		(92,952)
Preferred Stock Dividends			(1,442)		(1,442)
Capital Stock Expense		1,456	(1,456)		-
TOTAL					1,032,307
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $861				(1,580)	(1,580)
Minimum Pension Liability, Net of Tax of $37,779				(70,162)	(70,162)
NET INCOME			205,492		205,492
TOTAL COMPREHENSIVE INCOME					133,750
DECEMBER 31, 2002	260,458	717,242	260,439	(72,082)	1,166,057
Common Stock Dividends			(128,266)		(128,266)
Preferred Stock Dividends			(1,001)		(1,001)
Capital Stock Expense		2,494	(2,494)		-
SFAS 71 Capitalization		163			163
TOTAL					1,036,953
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $199				351	351
Minimum Pension Liability, Net of Tax of $10,577				19,643	19,643
NET INCOME			280,040		280,040
TOTAL COMPREHENSIVE INCOME					300,034
DECEMBER 31, 2003	260,458	719,899	408,718	(52,088)	1,336,987
Common Stock Dividends			(50,000)		(50,000)
Preferred Stock Dividends			(800)		(800)
Capital Stock Expense		2,415	(2,415)		-
TOTAL					1,286,187
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,176				(7,755)	(7,755)
Minimum Pension Liability, Net of Tax of $11,754				(21,829)	(21,829)
NET INCOME			153,115		153,115
TOTAL COMPREHENSIVE INCOME					123,531
DECEMBER 31, 2004	$ 260,458	$ 722,314	$ 508,618	$ (81,672)	$ 1,409,718

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 2,502,273	$ 2,287,043
Transmission	1,255,390	1,240,889
Distribution	2,070,377	2,006,329
General	302,474	294,786
Construction Work in Progress	399,116	311,884
Total	6,529,630	6,140,931
Accumulated Depreciation and Amortization	2,443,218	2,321,360
TOTAL - NET	4,086,412	3,819,571
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	20,378	20,574
Other Investments	18,775	26,668
TOTAL	39,153	47,242
CURRENT ASSETS		
Cash and Cash Equivalents	536	4,561
Other Cash Deposits	1,133	41,320
Accounts Receivable:		
Customers	126,422	133,717
Affiliated Companies	140,950	137,281
Accrued Unbilled Revenues	51,427	35,020
Miscellaneous	1,264	3,961
Allowance for Uncollectible Accounts	(5,561)	(2,085)
Risk Management Assets	81,811	71,189
Fuel	45,756	42,806
Materials and Supplies	45,644	41,959
Margin Deposits	8,329	11,525
Prepayments and Other	12,192	13,301
TOTAL	509,903	534,555
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	343,415	325,889
Transition Regulatory Assets	25,467	30,855
Unamortized Loss on Reacquired Debt	18,157	19,005
Other	36,368	41,447
Long-term Risk Management Assets	81,245	70,900
Emission Allowances	38,931	30,019
Deferred Property Taxes	37,071	35,343
Deferred Charges and Other	23,796	22,185
TOTAL	604,450	575,643
TOTAL ASSETS	$ 5,239,918	$ 4,977,011

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2004 and 2003

	2004	2003
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity		
Common Stock - No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	$ 260,458	$ 260,458
Paid-in Capital	722,314	719,899
Retained Earnings	508,618	408,718
Accumulated Other Comprehensive Income (Loss)	(81,672)	(52,088)
Total Common Shareholder's Equity	1,409,718	1,336,987
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784
Total Shareholders' Equity	1,427,502	1,354,771
Cumulative Preferred Stock Subject to Mandatory Redemption	-	5,360
Long-term Debt – Nonaffiliated	1,254,588	1,703,073
TOTAL	2,682,090	3,063,204
CURRENT LIABILITIES		
Long-term Debt Due Within One Year – Nonaffiliated	530,010	161,008
Advances from Affiliates	211,060	82,994
Accounts Payable:		
General	130,710	140,497
Affiliated Companies	76,314	81,812
Risk Management Liabilities	89,136	51,430
Taxes Accrued	90,404	50,259
Interest Accrued	21,076	22,113
Customer Deposits	42,822	33,930
Obligations Under Capital Leases	6,742	9,218
Other	56,645	60,289
TOTAL	1,254,919	693,550
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	852,536	803,355
Regulatory Liabilities:		
Asset Removal Costs	95,763	92,497
Over-recovery of Fuel Cost	57,843	68,704
Deferred Investment Tax Credits	30,382	30,545
Other	23,270	17,326
Employee Benefits and Pension Obligations	130,530	102,463
Long-term Risk Management Liabilities	57,349	54,327
Asset Retirement Obligations	24,626	21,776
Obligations Under Capital Leases	13,136	16,134
Deferred Credits	17,474	13,130
TOTAL	1,302,909	1,220,257
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,239,918	$ 4,977,011

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 153,115	$ 280,040	$ 205,492
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Changes	-	(77,257)	-
Depreciation and Amortization	193,525	175,772	189,335
Deferred Income Taxes	47,585	24,563	16,777
Deferred Investment Tax Credits	(163)	(3,146)	(4,637)
Deferred Property Taxes	(1,728)	(20)	(1,897)
Over/Under Fuel Recovery	(10,861)	74,071	6,365
Mark-to-Market of Risk Management Contracts	5,391	56,409	(21,151)
Change in Other Noncurrent Assets	(16,474)	(12,333)	(50,236)
Change in Other Noncurrent Liabilities	26,026	31,753	(5,233)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(6,608)	(6,825)	(83,453)
Fuel, Materials and Supplies	(6,635)	4,717	11,016
Accounts Payable	(15,285)	(17,611)	27,805
Taxes Accrued	40,145	21,078	(26,402)
Customer Deposits	8,892	7,744	13,008
Interest Accrued	(1,037)	(324)	667
Other Current Assets	4,303	(11,429)	2,510
Other Current Liabilities	(6,117)	(10,325)	743
Rate Stabilization Deferral	-	(75,601)	-
Net Cash Flows From Operating Activities	414,074	461,276	280,709
INVESTING ACTIVITIES			
Construction Expenditures	(452,173)	(288,800)	(276,549)
Change in Other Cash Deposits, Net	40,187	(41,168)	6,099
Proceeds from Sale of Assets	3,591	2,192	-
Other	-	-	1,074
Net Cash Flows Used For Investing Activities	(408,395)	(327,776)	(269,376)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	124,398	580,649	647,401
Issuance of Long-term Debt - Affiliated	-	-	-
Retirement of Long-term Debt	(206,008)	(622,737)	(315,007)
Retirement of Preferred Stock	(5,360)	(5,506)	-
Change in Short-term Debt, Net	-	-	-
Change in Advances to/from Affiliates, Net	128,066	43,789	(252,612)
Dividends Paid on Common Stock	(50,000)	(128,266)	(92,952)
Dividends Paid on Cumulative Preferred Stock	(800)	(1,001)	(1,442)
Net Cash Flows Used For Financing Activities	(9,704)	(133,072)	(14,612)
Net Increase (Decrease) in Cash and Cash Equivalents	(4,025)	428	(3,279)
Cash and Cash Equivalents at Beginning of Period	4,561	4,133	7,412
Cash and Cash Equivalents at End of Period	$ 536	$ 4,561	$ 4,133

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $92,773,000, $108,045,000 and $111,528,000 and for income taxes was $(831,000), $62,673,000 and $125,120,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $3,791,000.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF PREFERRED STOCK
December 31, 2004 and 2003

	2004	2003
	(in thousands)	

PREFERRED STOCK:
No Par Value - Authorized 8,000,000 shares

Series	Call Price December 31, 2004 (a)	Number of Shares Redeemed Year Ended December 31, 2004	2003	2002	Shares Outstanding December 31, 2004	2004	2003
Not Subject to Mandatory Redemption - $100 Par:							
4.50%	$110	3	60	6	177,836	$ 17,784	$ 17,784
Subject to Mandatory Redemption - $100 Par (b):							
5.90%		22,100	25,000	-	-	-	2,210
5.92%		31,500	30,000	-	-	-	3,150
Total						$ -	$ 5,360

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends. The involuntary liquidation preference is $100 per share. The aggregate involuntary liquidation price for all shares of cumulative preferred stock may not exceed $300 million. The unissued shares of the cumulative preferred stock may or may not possess mandatory redemption characteristics upon issuance.

(b) The sinking fund provisions of each series subject to mandatory redemption have been met by shares purchased in advance of the due date.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
December 31, 2004 and 2003

	2004	2003
	(in thousands)	
LONG-TERM DEBT:		
First Mortgage Bonds	$ 224,662	$ 340,269
Installment Purchase Contracts	236,759	276,477
Senior Unsecured Notes	1,320,663	1,244,813
Other Long-term Debt	2,514	2,522
Less Portion Due Within One Year	(530,010)	(161,008)
Long-term Debt Excluding Portion Due Within One Year	$ 1,254,588	$ 1,703,073

There are certain limitations on establishing liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.700	2004 – September 1	$ -	$ 21,000
7.850	2004 – November 1	-	50,000
8.000	2005 – May 1	50,000	50,000
6.890	2005 – June 22	30,000	30,000
6.800	2006 – March 1	100,000	100,000
7.125	2024 – May 1	-	45,000
8.000	2025 – June 1	45,000	45,000
Unamortized Discount		(338)	(731)
Total		$ 224,662	$ 340,269

First Mortgage Bonds are secured by a first mortgage lien on Electric Utility Plant. Certain supplemental indentures to the first mortgage lien contain maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment Purchase Contracts have been entered into, in connection with the issuance of pollution control revenue bonds, by governmental authorities as follows:

	% Rate	Due	2004	2003
			(in thousands)	
Industrial Development Authority	(a)	2007 – November 1	$ 17,500	$ 17,500
of Russell County, Virginia	5.000	2021 – November 1	19,500	19,500
Putnam County, West Virginia	(b)	2019 – June 1	40,000	40,000
	5.450	2019 – June 1	-	40,000
	(c)	2019 – May 1	30,000	30,000
Mason County, West Virginia	6.050	2024 – December 1	30,000	30,000
	5.500	2022 – October 1	100,000	100,000
	Unamortized Discount		(241)	(523)
	Total		$ 236,759	$ 276,477

(a) Rate is an annual long-term fixed rate of 2.70% through November 1, 2006. After that date the rate may be daily, weekly, commercial paper, auction or other long-term rate as designated by us (fixed rate bonds).
(b) In December 2003, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The rate on December 31, 2004 was 1.85%.

(c) Rate is an annual long-term fixed rate of 2.80% through November 1, 2006. After that date the rate may be daily, weekly, commercial paper, auction or other long-term rate as designated by us (fixed rate bonds).

Under the terms of the installment purchase contracts, we are required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.450	2004 – November 1	$ -	$ 50,000
4.800	2005 – June 15	450,000	450,000
4.320	2007 – November 12	200,000	200,000
3.600	2008 – May 15	200,000	200,000
6.600	2009 – May 1	150,000	150,000
5.950	2033 – May 15	200,000	200,000
(a)	2007 – June 29	125,000	-
Unamortized Discount		(4,337)	(5,187)
Total		$ 1,320,663	$ 1,244,813

(a) Floating rate determined quarterly. The rate at December 31, 2004 was 2.88%.

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount (in thousands)
2005	$ 530,010
2006	100,011
2007	342,513
2008	200,014
2009	150,017
Later Years	466,949
Total Principal Amount	1,789,514
Unamortized Discount	(4,916)
Total	$ 1,784,598

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to APCo's consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Appalachian Power Company:

We have audited the accompanying consolidated balance sheets of Appalachian Power Company and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Appalachian Power Company and subsidiaries 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.

As discussed in Note 2 to the consolidated financial statements, the Company adopted 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 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 1,433,581	$ 1,431,851	$ 1,400,160	$ 1,350,319	$ 1,304,409
Operating Income	184,246	225,486	219,779	252,177	195,877
Interest Charges	54,246	50,948	53,869	68,015	80,828
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	140,258	173,147	181,173	191,900	120,202
Extraordinary Loss, Net of Tax	-	-	-	(30,024)	(25,236)
Cumulative Effect of Accounting Changes, Net of Tax	-	27,283	-	-	-
Net Income	140,258	200,430	181,173	161,876	94,966
BALANCE SHEETS DATA					
Electric Utility Plant	$ 3,691,246	$ 3,570,443	$ 3,467,626	$ 3,354,320	$ 3,266,794
Accumulated Depreciation and Amortization	1,471,950	1,389,586	1,369,153	1,283,712	1,211,728
Net Electric Utility Plant	$ 2,219,296	$ 2,180,857	$ 2,098,473	$ 2,070,608	$ 2,055,066
TOTAL ASSETS	$ 3,029,896	$ 2,838,366	$ 2,849,261	$ 2,815,708	$ 3,965,460
Common Shareholder's Equity	898,650	897,881	847,664	791,498	713,449
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	-	-	-	10,000	15,000
Long-term Debt (a)	987,626	897,564	621,626	791,848	899,615
Obligations Under Capital Leases (a)	12,514	15,618	27,610	34,887	42,932

(a) Including portion due within one year.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

CSPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 707,000 retail customers in central and southern Ohio. We consolidate Colomet, Inc., Conesville Coal Preparation Company and Simco, Inc., our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers.

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

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated 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 via the AEP Power Pool, discussed above.

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 the new environment. We are confident in our ability to participate successfully in the PJM market.

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

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

2004 Compared to 2003

During 2004, Net Income decreased by $60 million primarily due to a $27 million net of tax Cumulative Effect of Accounting Changes recorded in 2003, an $18 million increase in purchased power expenses and $14 million in expenses resulting from a December 2004 ice storm.

Operating Income

Operating Income decreased by $41 million primarily due to:

- A $22 million decrease in nonaffiliated wholesale energy sales and related transmission services due to lower sales volume and the expiration of municipal contracts.
- A $20 million increase in Maintenance expense primarily associated with costs incurred as a result of a major ice storm in late December 2004 and boiler overhaul work from scheduled and forced outages.
- An $18 million increase in purchased power expenses primarily due to increased purchases from the AEP Power Pool and PJM regional transmission authority.
- A $13 million increase in Depreciation and Amortization expense due to a greater depreciable base in 2004, including capitalized software costs and the increased amortization of transition generation regulatory assets due to normal operating adjustments.
- A $9 million increase in Other Operation expense primarily relating to pension plan costs, steam removal costs and administrative and support expenses, partially offset by increased gains on the disposition of emission allowances.
- A $2 million decrease in affiliated wholesale energy sales due to lower sales volume.

The decrease in Operating Income was partially offset by:

- A $21 million increase in retail electric revenues resulting primarily from increased weather-related demand from residential and commercial customers during the second quarter of 2004.
- A $15 million decrease in Income Taxes expense. See Income Taxes section below for further discussion.
- A $9 million increase in operating revenues related to favorable results from risk management activities.

Other Impacts on Earnings

Nonoperating Income (Loss) increased $18 million primarily due to favorable results from risk management activities.

Nonoperating Income Tax Expense (Credit) increased $9 million. See Income Taxes section below for further discussion.

Income Taxes

The effective tax rates for 2004 and 2003 were 32.5% and 29.8%, 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, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is primarily due to higher state income taxes, lower consolidated tax savings from Parent, and less favorable income tax adjustments.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	A3	BBB	A-

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:

Payment 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)	$ 36.0	$ -	$ 112.0	$ 842.2	$ 990.2
Advances to Affiliates (b)	141.6	-	-	-	141.6
Capital Lease Obligations (c)	4.5	5.3	3.2	1.0	14.0
Noncancelable Operating Leases (c)	5.7	5.9	3.8	3.2	18.6
Fuel Purchase Contracts (d)	135.8	198.1	55.3	-	389.2
Energy and Capacity Purchase Contracts (e)	11.4	17.0	-	-	28.4
Total	$ 335.0	$ 226.3	$ 174.3	$ 846.4	$ 1,582.0

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.
(b) Represents short-term borrowings from the Utility Money Pool.
(c) See Note 15.
(d) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(e) Represents contractual cash flows of energy and capacity purchase contracts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2004 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)	$ -	$ 44.1	$ -	$ -	$ 44.1

(a) We have issued standby letters of credit to third parties. These letters of credit cover 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 $44.1 million maturing in April 2007. There is no recourse to third parties in the event these letters of credit are drawn.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

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

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

Total MTM Risk Management Contract Net Assets at December 31, 2003	$	38,337
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(19,805)
Fair Value of New Contracts When Entered During the Period (b)		2,493
Net Option Premiums Paid/(Received) (c)		(260)
Change in Fair Value Due to Valuation Methodology Changes (d)		898
Changes in Fair Value of Risk Management Contracts (e)		9,256
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)		-
Total MTM Risk Management Contract Net Assets		30,919
Net Cash Flow Hedge Contracts (g)		1,198
DETM Assignment (h)		(13,654)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$	18,463

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

(b) "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 that were 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, 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 Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

(h) See "AEP East Companies" in Note 17.

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

	MTM Risk Management Contracts (a)	Cash Flow Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 38,275	$ 8,356	$ -	$ 46,631
Noncurrent Assets	46,724	11	-	46,735
Total MTM Derivative Contract Assets	84,999	8,367	-	93,366
Current Liabilities	(28,885)	(6,610)	(6,677)	(42,172)
Noncurrent Liabilities	(25,195)	(559)	(6,977)	(32,731)
Total MTM Derivative Contract Liabilities	(54,080)	(7,169)	(13,654)	(74,903)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 30,919	$ 1,198	$ (13,654)	$ 18,463

(a) Does not include Cash Flow Hedges.
(b) See "AEP East Companies" in Note 17.
(c) 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of December 31, 2004
(in thousands)**

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (2,715)	$ (98)	$ 1,365	$ -	$ -	$ -	$ (1,448)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	12,650	5,227	4,611	1,656	-	-	24,144
Prices Based on Models and Other Valuation Methods (b)	(545)	(548)	(571)	2,518	3,590	3,779	8,223
Total	$ 9,390	$ 4,581	$ 5,405	$ 4,174	$ 3,590	$ 3,779	$ 30,919

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in 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 are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

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 operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges 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. In accordance with GAAP, all amounts are presented net of related income taxes.

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

	Power
Beginning Balance December 31, 2003	$ 202
Changes in Fair Value (a)	2,304
Reclassifications from AOCI to Net Income (b)	(1,113)
Ending Balance December 31, 2004	$ 1,393

(a) "Changes in Fair Value" shows 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.

(b) "Reclassifications from AOCI to Net Income" represents 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.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,750 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Energy and Gas Risk Management Contracts

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

December 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$332	$1,083	$467	$160	$336	$1,303	$546	$130

VaR Associated with Debt Outstanding

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 $48 million and $98 million at December 31, 2004 and 2003, respectively. 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 negatively affect our results of operations or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,353,466	$ 1,347,482	$ 1,342,958
Sales to AEP Affiliates	80,115	84,369	57,202
TOTAL	1,433,581	1,431,851	1,400,160
OPERATING EXPENSES			
Fuel for Electric Generation	191,578	176,071	157,569
Fuel From Affiliates for Electric Generation	10,603	27,328	27,517
Purchased Energy for Resale	26,267	17,730	15,023
Purchased Electricity from AEP Affiliates	347,002	337,323	310,605
Other Operation	227,112	218,466	237,802
Maintenance	95,036	75,319	60,003
Depreciation and Amortization	148,529	135,964	131,624
Taxes Other Than Income Taxes	133,840	133,754	136,024
Income Taxes	69,368	84,410	104,214
TOTAL	1,249,335	1,206,365	1,180,381
OPERATING INCOME	184,246	225,486	219,779
Nonoperating Income (Loss)	10,341	(7,489)	28,280
Nonoperating Expenses	1,780	4,650	6,228
Nonoperating Income Tax Expense (Credit)	(1,697)	(10,748)	6,789
Interest Charges	54,246	50,948	53,869
Income Before Cumulative Effect of Accounting Changes	140,258	173,147	181,173
Cumulative Effect of Accounting Changes, Net of Tax	-	27,283	-
NET INCOME	140,258	200,430	181,173
Preferred Stock Dividend Requirements including Capital Stock Expense	1,015	1,016	1,365
EARNINGS APPLICABLE TO COMMON STOCK	$ 139,243	$ 199,414	$ 179,808

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 41,026	$ 574,369	$ 176,103	$ -	$ 791,498
Common Stock Dividends			(65,300)		(65,300)
Preferred Stock Dividends			(350)		(350)
Capital Stock Expense		1,015	(1,015)		-
TOTAL					725,848
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $144				(267)	(267)
Minimum Pension Liability, Net of Tax of $31,818				(59,090)	(59,090)
NET INCOME			181,173		181,173
TOTAL COMPREHENSIVE INCOME					121,816
DECEMBER 31, 2002	41,026	575,384	290,611	(59,357)	847,664
Common Stock Dividends			(163,243)		(163,243)
Capital Stock Expense		1,016	(1,016)		-
TOTAL					684,421
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $253				469	469
Minimum Pension Liability, Net of Tax of $6,763				12,561	12,561
NET INCOME			200,430		200,430
TOTAL COMPREHENSIVE INCOME					213,460
DECEMBER 31, 2003	41,026	576,400	326,782	(46,327)	897,881
Common Stock Dividends			(125,000)		(125,000)
Capital Stock Expense		1,015	(1,015)		-
TOTAL					772,881
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $641				1,191	1,191
Minimum Pension Liability, Net of Tax of $8,443				(15,680)	(15,680)
NET INCOME			140,258		140,258
TOTAL COMPREHENSIVE INCOME					125,769
DECEMBER 31, 2004	$ 41,026	$ 577,415	$ 341,025	$ (60,816)	$ 898,650

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 1,658,552	$ 1,610,888
Transmission	432,714	425,512
Distribution	1,300,252	1,253,760
General	167,985	166,002
Construction Work in Progress	131,743	114,281
Total	3,691,246	3,570,443
Accumulated Depreciation and Amortization	1,471,950	1,389,586
TOTAL - NET	2,219,296	2,180,857
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	22,322	22,417
Other Investments	5,147	8,663
TOTAL	27,469	31,080
CURRENT ASSETS		
Cash and Cash Equivalents	25	3,377
Other Cash Deposits	33	765
Advances to Affiliates	141,550	-
Accounts Receivable:		
Customers	41,130	47,099
Affiliated Companies	72,854	68,168
Accrued Unbilled Revenues	19,580	23,723
Miscellaneous	1,145	5,257
Allowance for Uncollectible Accounts	(674)	(531)
Fuel	34,026	14,365
Materials and Supplies	37,137	26,102
Risk Management Assets	46,631	40,095
Margin Deposits	4,848	6,636
Prepayments and Other	11,499	12,444
TOTAL	409,784	247,500
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	16,481	16,027
Transition Regulatory Assets	156,676	188,532
Unamortized Loss on Reacquired Debt	13,155	13,659
Other	25,691	24,966
Long-term Risk Management Assets	46,735	39,932
Deferred Property Taxes	64,754	62,262
Deferred Charges and Other	49,855	33,551
TOTAL	373,347	378,929
TOTAL ASSETS	$ 3,029,896	$ 2,838,366

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2004 and 2003

CAPITALIZATION	2004	2003
	(in thousands)	
Common Shareholder's Equity:		
Common Stock - No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	$ 41,026	$ 41,026
Paid-in Capital	577,415	576,400
Retained Earnings	341,025	326,782
Accumulated Other Comprehensive Income (Loss)	(60,816)	(46,327)
Total Common Shareholder's Equity	898,650	897,881
Preferred Stock – No Shares Outstanding	-	-
Authorized – 2,500,000 Shares at $100 Par Value		
Authorized – 7,000,000 Shares at $25 Par Value		
Total Shareholder's Equity	898,650	897,881
Long-term Debt:		
Nonaffiliated	851,626	886,564
Affiliated	100,000	-
Total Long-term Debt	951,626	886,564
TOTAL	1,850,276	1,784,445
CURRENT LIABILITIES		
Long-term Debt Due Within One Year – Nonaffiliated	36,000	11,000
Advances from Affiliates, Net	-	6,517
Accounts Payable:		
General	63,606	58,220
Affiliated Companies	45,745	53,572
Customer Deposits	24,890	19,727
Taxes Accrued	195,284	132,853
Interest Accrued	16,320	16,528
Risk Management Liabilities	42,172	28,966
Obligations Under Capital Leases	3,854	4,221
Other	24,338	25,364
TOTAL	452,209	356,968
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	464,545	458,498
Regulatory Liabilities:		
Asset Removal Costs	103,104	99,119
Deferred Investment Tax Credits	27,933	30,797
Employee Benefits and Pension Obligations	62,778	40,341
Long-term Risk Management Liabilities	32,731	30,598
Obligations Under Capital Leases	8,660	11,397
Asset Retirement Obligations	11,585	8,740
Deferred Credits and Other	16,075	17,463
TOTAL	727,411	696,953
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 3,029,896	$ 2,838,366

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 140,258	$ 200,430	$ 181,173
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Changes	-	(27,283)	-
Depreciation and Amortization	148,529	135,964	131,753
Deferred Income Taxes	13,395	(4,514)	23,292
Deferred Investment Tax Credits	(2,864)	(3,110)	(3,270)
Deferred Property Tax	(2,492)	(529)	(13,732)
Mark-to-Market of Risk Management Contracts	2,887	41,830	(16,667)
Change in Other Noncurrent Assets	(18,591)	(12,162)	(19,747)
Change in Other Noncurrent Liabilities	2,351	(21,286)	(17,303)
Changes in Components of Working Capital:			
Accounts Receivable, Net	9,681	(5,590)	(9,576)
Fuel, Materials and Supplies	(30,696)	9,812	(1,002)
Accounts Payable	(2,441)	(59,543)	26,949
Taxes Accrued	62,431	20,681	(4,192)
Interest Accrued	(208)	6,730	(1,108)
Customer Deposits	5,163	5,009	8,834
Other Current Assets	2,731	(11,770)	21,426
Other Current Liabilities	(1,394)	7,514	(9,829)
Net Cash Flows From Operating Activities	328,740	282,183	297,001
INVESTING ACTIVITIES			
Construction Expenditures	(149,788)	(136,291)	(136,800)
Change in Other Cash Deposits, Net	732	16	58
Proceeds from Sale of Assets	3,393	1,644	730
Net Cash Flows Used For Investing Activities	(145,663)	(134,631)	(136,012)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Affiliated	100,000	-	160,000
Issuance of Long-term Debt – Nonaffiliated	89,883	643,097	-
Change in Advances to/from Affiliates, Net	(148,067)	37,774	(212,641)
Retirement of Long-term Debt – Nonaffiliated	(103,245)	(212,500)	(133,343)
Retirement of Long-term Debt - Affiliated	-	(160,000)	(200,000)
Retirement of Cumulative Preferred Stock	-	-	(10,000)
Change in Short-term Debt – Affiliates	-	(290,000)	290,000
Dividends Paid on Common Stock	(125,000)	(163,243)	(65,300)
Dividends Paid on Cumulative Preferred Stock	-	-	(525)
Net Cash Flows Used For Financing Activities	(186,429)	(144,872)	(171,809)
Net Increase (Decrease) in Cash and Cash Equivalents	(3,352)	2,680	(10,820)
Cash and Cash Equivalents at Beginning of Period	3,377	697	11,517
Cash and Cash Equivalents at End of Period	$ 25	$ 3,377	$ 697

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $48,461,000, $42,601,000 and $53,514,000 and for income taxes was $(5,281,756), $63,907,000 and $117,591,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $1,302,000. There were no noncash capital lease acquisitions in 2003 or 2002.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
December 31, 2004 and 2003

	2004	2003
LONG-TERM DEBT:	(in thousands)	
First Mortgage Bonds	$ -	$ 10,944
Installment Purchase Contracts	92,077	91,329
Senior Unsecured Notes	795,549	795,291
Notes Payable – Affiliated	100,000	-
Less Portion Due Within One Year	(36,000)	(11,000)
Long-term Debt Excluding Portion Due Within One Year	$ 951,626	$ 886,564

There are certain limitations on establishing additional liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.60	2024 – May 1	$ -	$ 11,000
Unamortized Discount		-	(56)
Total		$ -	$ 10,944

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by the Ohio Air Quality Development Authority:

% Rate	Due	2004	2003
		(in thousands)	
6.375	2020 – December 1	$ -	$ 48,550
6.250	2020 – December 1	-	43,695
(a)	2038 – December 1	43,695	-
(b)	2038 – December 1	48,550	-
Unamortized Discount		(168)	(916)
Total		$ 92,077	$ 91,329

(a) A floating interest rate is determined weekly and paid monthly. The rate on December 31, 2004 was 2.00%. The bonds would be subject to mandatory tender on April 27, 2007 if the letter of credit backing this issuance were not renewed at that time or if the current letter of credit provider were replaced by a new provider.

(b) In 2004, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate for 2004 ranged from 1.05% to 1.75% and averaged 1.50%. The rate on December 31, 2004 was 1.75%. Interest payments are made every 35 days.

Under the terms of the Installment Purchase Contracts, we are required to pay amounts sufficient to enable the payment of interest on and the principal of related pollution control revenue bonds (at stated maturities and upon mandatory redemptions) issued to finance the construction of pollution control facilities at the Zimmer Plant.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.850	2005 – October 3	$ 36,000	$ 36,000
6.510	2008 – February 1	52,000	52,000
6.550	2008 – June 26	60,000	60,000
4.400	2010 – December 1	150,000	150,000
5.500	2013 – March 1	250,000	250,000
6.600	2033 – March 1	250,000	250,000
Unamortized Discount		(2,451)	(2,709)
Total		$ 795,549	$ 795,291

Notes Payable to Parent were as follows:

% Rate	Due	2004	2003
		(in thousands)	
4.64	2010 – March 15	$ 100,000	$ -

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ 36,000
2006	-
2007	-
2008	112,000
2009	-
Later Years	842,245
Total Principal Amount	990,245
Unamortized Discount	(2,619)
Total	$ 987,626

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to CSPCo's consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to CSPCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Columbus Southern Power Company:

We have audited the accompanying consolidated balance sheets of Columbus Southern Power Company and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Columbus Southern Power Company and subsidiaries 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.

As discussed in Note 2 to the consolidated financial statements, the Company adopted 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 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF OPERATIONS DATA					
Operating Revenues	$ 1,661,580	$ 1,595,596	$ 1,526,764	$ 1,526,997	$ 1,488,209
Operating Income (Loss)	195,888	186,067	151,189	159,705	(34,702)
Interest Charges	69,071	83,054	93,923	93,647	107,263
Net Income (Loss) Before Cumulative Effect of Accounting Change	133,222	89,548	73,992	75,788	(132,032)
Cumulative Effect of Accounting Change, Net of Tax	-	(3,160)	-	-	-
Net Income (Loss)	133,222	86,388	73,992	75,788	(132,032)
BALANCE SHEETS DATA					
Electric Utility Plant	$ 5,562,397	$ 5,306,182	$ 5,029,958	$ 4,923,721	$ 4,871,473
Accumulated Depreciation and Amortization	2,603,479	2,490,912	2,318,063	2,198,524	2,057,542
Net Electric Utility Plant	$ 2,958,918	$ 2,815,270	$ 2,711,895	$ 2,725,197	$ 2,813,931
Total Assets	$ 4,868,141	$ 4,659,071	$ 4,837,732	$ 4,632,510	$ 5,997,087
Common Shareholder's Equity	1,091,498	1,078,047	1,018,653	860,570	793,099
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,084	8,101	8,101	8,736	8,736
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	61,445	63,445	64,945	64,945	64,945
Long-term Debt (a)	1,312,843	1,339,359	1,617,062	1,652,082	1,388,939
Obligations Under Capital Leases (a)	50,732	37,843	50,848	61,933	163,173

(a) Including portion due within one year.

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 579,000 retail customers in our service territory in northern and eastern Indiana and a portion of southwestern Michigan. We consolidate Blackhawk Coal Company and Price River Coal Company, our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities and electric cooperatives.

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

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of each year. In 2002, the capacity based allocation mechanism was not triggered.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated 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 via the AEP Power Pool, discussed above.

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 the new environment. We are confident in our ability to participate successfully in the PJM market.

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

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

During 2004, Net Income increased $47 million as gross margin (revenues less the cost of fuel and purchased energy) increased $26 million and interest charges declined $14 million. The improvement in gross margin reflects increased retail sales and the end of amortization for the Cook Plant outage settlements.

During 2003, Net Income increased $12 million including an unfavorable $3 million Cumulative Effect of Accounting Change (see "Cummulative Effect of Accounting Change" section of Note 2). During 2003, Net Income Before Cumulative Effect of Accounting Change increased $15 million due to reduced financing costs and an improvement in Operating Income resulting from higher margins on wholesale sales and lower Other Operation expenses.

2004 Compared to 2003

Operating Income increased $10 million primarily due to:

- A $54 million increase in Electric Generation, Transmission and Distribution revenues due to an increase in commercial and industrial sales reflecting the economic recovery and the end of amortization of Cook Plant outage settlements and an increase in revenues from coal trading sales.
- A $14 million decrease in Other Operation expenses primarily due to the end of amortization of Cook Plant outage settlements.
- A $12 million increase in Sales to AEP Affiliates reflecting increased availability of the Cook Plant units.
- A $2 million decrease in Purchased Electricity from AEP Affiliates primarily due to an increase in net generation of 11% that reduced our need to purchase power from affiliates.

The increase in Operating Income was partially offset by:

- A $29 million increase in Fuel for Electric Generation expenses reflecting an increase in total generation of 11%.
- A $19 million increase in Income Taxes expense. See Income Taxes section below for further discussion.
- A $14 million increase in Purchased Energy for Resale expenses reflecting new costs related to PJM membership and coal trading purchases under procurement contracts.
- A $10 million increase in Maintenance expenses primarily due to increased maintenance expenses at the Cook Plant and increased costs for distribution right of way, line maintenance and storm damage repair.

Other Impacts on Earnings

Nonoperating Income increased $25 million primarily due to favorable results from risk management activities and increased barging revenues.

Nonoperating Expenses decreased $6 million primarily due to a $10 million write-down in 2003 of western coal lands (see "Blackhawk Coal Company" section of Note 10).

Nonoperating Income Tax Expense increased $11 million. See Income Taxes section below for further discussion.

Interest Charges decreased $14 million primarily due to a reduction in outstanding long-term debt and lower interest rates from refunding higher cost debt.

Income Taxes

The effective tax rates for 2004 and 2003 were 35% and 31.5%, 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, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is due primarily to changes in flow-through of book versus tax temporary differences and an increase in state income taxes.

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change of $3 million in the prior year is due to the implementation of the requirements of EITF 02-3 related to mark-to-market accounting for risk management contracts that are not derivatives (see "Cumulative Effect of Accounting Change" section of Note 2).

2003 Compared to 2002

Operating Income

Operating Income increased $35 million primarily due to:

- A $69 million increase in wholesale sales including system and power optimization sales, transmission revenues and risk management activities reflecting availability of AEP's generation and market conditions.
- A $45 million decrease in Other Operation expenses primarily due to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits of $15 million recorded in 2002.
- A $35 million increase in Sales to AEP Affiliates due to increased capacity revenue.

The increase in Operating Income was partially offset by:

- A $41 million increase in Purchased Electricity from AEP Affiliates due to purchasing more power from the AEP Power Pool to support wholesale sales to nonaffiliated entities.
- A $37 million decrease in retail revenues primarily due to milder summer weather and economic pressures on industrial customers. Cooling degree days declined approximately 42% this year compared with last year. Industrial revenues declined 3% from prior year.
- A $12 million increase in Income Taxes expense. See Income Taxes section below for further discussion.
- An $11 million increase in Fuel for Electric Generation expense reflecting an increase in the average cost of fuel and increased coal-fired generation in 2003 as Rockport's availability increased.

Other Impacts on Earnings

Nonoperating Income decreased $30 million primarily due to lower margins for power sold outside of AEP's traditional market reflecting AEP's plan to exit those risk management activities.

Nonoperating Expenses increased $16 million primarily due to a $10 million write-down of western coal lands (see "Blackhawk Coal Company" section of Note 10).

Nononperating Income Tax Expense decreased $16 million. See Income Taxes section below for further discussion.

Interest Charges decreased $11 million primarily due to a reduction in outstanding long-term debt of $255 million which was retired in May 2003 using lower rate short-term debt.

Income Taxes

The effective tax rates for 2003 and 2002 were 31.5% and 37.7%, 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, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is due primarily to changes in flow-through of book versus tax temporary differences and federal income tax adjustments, offset, in part, by an increase in state income taxes.

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change of $3 million in 2003 is due to the implementation of the requirements of EITF 02-3 (see "Cumulative Effect of Accounting Change " section of Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings, unchanged since first quarter of 2003, are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

Cash Flow

Cash flows for 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(in thousands)	
Cash and cash equivalents at beginning of period	$ 3,899	$ 3,250	$ 6,705
Cash flows from (used for):			
Operating activities	412,123	222,821	228,234
Investing activities	(174,038)	(182,779)	(155,613)
Financing activities	(241,519)	(39,393)	(76,076)
Net increase (decrease) in cash and cash equivalents	(3,434)	649	(3,455)
Cash and cash equivalents at end of period	$ 465	$ 3,899	$ 3,250

Operating Activities

Our net cash flows from operating activities were $412 million in 2004. We produced Net Income of $133 million during the period and noncash expense items of $172 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant relates to Taxes Accrued. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP 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.

Our net cash flows from operating activities were $223 million in 2003. We produced Net Income of $86 million during the period and noncash expense items of $171 million for Depreciation and Amortization and $78 million for the Cook Plant outage settlement agreements. The other changes in assets and liabilities represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant was a $35 million change in net accounts receivable/payable related to the timing of settlements with our affiliates and $29 million related to Taxes Accrued related to the timing of estimated federal income tax payments.

Our net cash flows from operating activities were $228 million in 2002. We produced Net Income of $74 million during the period and noncash expense items of $168 million for Depreciation and Amortization and $78 million for the Cook Plant outage settlement amortization. The other changes in assets and liabilities represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant was a $19 million change in net accounts receivable/payable related to the timing of settlements with our affiliates.

Investing Activities

Cash flows used for investing activities during 2004, 2003 and 2002 primarily reflect our construction expenditures of $177 million, $185 million and $167 million, respectively. Construction expenditures for the nuclear plant and transmission and distribution assets are to upgrade or replace equipment and improve reliability. In 2004, we also invested in capital projects to improve air quality and water intake systems.

Financing Activities

Our cash flows used for financing activities were $242 million in 2004. We used cash from operations to repay short-term debt and pay common dividends. In 2004, we issued $175 million in senior unsecured notes and refunded $97 million in fixed rate installment purchase contracts and reissued at variable rate.

Financing activities for 2003 used $39 million of cash from operations primarily to pay common dividends. During 2003, we redeemed $285 million of long-term debt using short-term debt and refinanced $65 million of our installment purchase contracts at a lower fixed rate through October 2006.

During 2002, we redeemed $340 million of long-term debt and $145 million of short-term debt using cash from operations, a $125 million capital contribution from our Parent and proceeds from the issuance of $289 million of long-term debt.

In January 2005, we redeemed $61 million Cumulative Preferred Stock Subject to Mandatory Redemption.

Off-Balance Sheet Arrangements

In prior years, we entered into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. The following identifies significant off-balance sheet arrangements:

Rockport Plant Unit 2

In 1989, AEGCo and I&M entered into a sale and leaseback transaction with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (Rockport 2). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $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 Rockport 2 and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the 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 Rockport 2. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

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:

Payment 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)	$ -	$ 415.0	$ 95.0	$ 805.9	$ 1,315.9
Preferred Stock Subject to Mandatory Redemption (b)	61.4	-	-	-	61.4
Capital Lease Obligations (c)	8.4	11.6	11.1	25.3	56.4
Noncancelable Operating Leases (c)	104.0	195.2	190.2	1,019.6	1,509.0
Fuel Purchase Contracts (d)	212.1	393.8	264.0	336.3	1,206.2
Energy and Capacity Purchase Contracts (e)	12.8	19.0	-	-	31.8
Total	$ 398.7	$ 1,034.6	$ 560.3	$ 2,187.1	$ 4,180.7

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.
(b) See Schedule of Preferred Stock.
(c) See Note 15. The lease of Rockport 2 is reported in Noncancelable Operating Leases.
(d) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(e) Represents contractual cash flows of energy and capacity purchase contracts.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

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

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

Total MTM Risk Management Contract Net Assets at December 31, 2003	$	41,995
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(15,476)
Fair Value of New Contracts When Entered During the Period (b)		-
Net Option Premiums Paid/(Received) (c)		(291)
Change in Fair Value Due to Valuation Methodology Changes (d)		-
Changes in Fair Value of Risk Management Contracts (e)		1,668
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)		6,677
Total MTM Risk Management Contract Net Assets		34,573
Net Cash Flow and Fair Value Hedge Contracts (g)		1,101
DETM Assignment (h)		(15,266)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$	20,408

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

(b) "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 that were 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, 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 Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

(h) See "AEP East Companies" in Note 17.

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

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 42,797	$ 9,344	$ -	$ 52,141
Noncurrent Assets	52,245	11	-	52,256
Total MTM Derivative Contract Assets	95,042	9,355	-	104,397
Current Liabilities	(32,297)	(7,412)	(7,465)	(47,174)
Noncurrent Liabilities	(28,172)	(842)	(7,801)	(36,815)
Total MTM Derivative Contract Liabilities	(60,469)	(8,254)	(15,266)	(83,989)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 34,573	$ 1,101	$ (15,266)	$ 20,408

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "AEP East Companies" in Note 17.
(c) 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of December 31, 2004
(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (3,035)	$ (110)	$ 1,526	$ -	$ -	$ -	$ (1,619)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	14,145	5,845	5,156	1,852	-	-	26,998
Prices Based on Models and Other Valuation Methods (b)	(610)	(613)	(638)	2,816	4,014	4,225	9,194
Total	$ 10,500	$ 5,122	$ 6,044	$ 4,668	$ 4,014	$ 4,225	$ 34,573

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in 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 are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow and Fair Value Hedges.

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 operations. We monitor these risks on our future operations and may employ various commodity instruments 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.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges 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. In accordance with GAAP, all amounts are presented net of related income taxes.

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

	Power	Interest Rate	Total
Beginning Balance December 31, 2003	$ 222	$ -	$ 222
Changes in Fair Value (a)	2,564	(5,705)	(3,141)
Reclassifications from AOCI to Net Income (b)	(1,228)	71	(1,157)
Ending Balance December 31, 2004	$ 1,558	$ (5,634)	$ (4,076)

(a) "Changes in Fair Value" shows 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.
(b) "Reclassifications from AOCI to Net Income" represents 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.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,386 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

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

December 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$371	$1,211	$522	$178	$368	$1,429	$598	$142

VaR Associated with Debt Outstanding

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 $53 million and $79 million at December 31, 2004 and 2003, respectively. 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 negatively affect our results of operations or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,400,406	$ 1,346,393	$ 1,312,626
Sales to AEP Affiliates	261,174	249,203	214,138
TOTAL	1,661,580	1,595,596	1,526,764
OPERATING EXPENSES			
Fuel for Electric Generation	279,518	250,890	239,455
Purchased Energy for Resale	41,888	28,327	23,443
Purchased Electricity from AEP Affiliates	272,452	274,400	233,724
Other Operation	403,702	417,636	462,707
Maintenance	168,304	158,281	151,602
Depreciation and Amortization	172,099	171,281	168,070
Taxes Other Than Income Taxes	57,344	57,788	57,721
Income Taxes	70,385	50,926	38,853
TOTAL	1,465,692	1,409,529	1,375,575
OPERATING INCOME	195,888	186,067	151,189
Nonoperating Income	79,247	53,928	84,084
Nonoperating Expenses	71,612	77,171	61,374
Nonoperating Income Tax Expense (Credit)	1,230	(9,778)	5,984
Interest Charges	69,071	83,054	93,923
Net Income Before Cumulative Effect of Accounting Change	133,222	89,548	73,992
Cumulative Effect of Accounting Change, Net of Tax	-	(3,160)	-
NET INCOME	133,222	86,388	73,992
Preferred Stock Dividend Requirements including Capital Stock Expense	474	2,509	4,601
EARNINGS APPLICABLE TO COMMON STOCK	$ 132,748	$ 83,879	$ 69,391

The common stock of I&M is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 56,584	$ 733,216	$ 74,605	$ (3,835)	$ 860,570
Capital Contribution from Parent Company		125,000			125,000
Preferred Stock Dividends			(4,467)		(4,467)
Capital Stock Expense		344	(134)		210
TOTAL					981,313
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,911				3,549	3,549
Minimum Pension Liability, Net of Tax of $21,646				(40,201)	(40,201)
NET INCOME			73,992		73,992
TOTAL COMPREHENSIVE INCOME					37,340
DECEMBER 31, 2002	56,584	858,560	143,996	(40,487)	1,018,653
Common Stock Dividends			(40,000)		(40,000)
Preferred Stock Dividends			(2,375)		(2,375)
Capital Stock Expense		134	(134)		-
TOTAL					976,278
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $273				508	508
Minimum Pension Liability, Net of Tax of $8,009				14,873	14,873
NET INCOME			86,388		86,388
TOTAL COMPREHENSIVE INCOME					101,769
DECEMBER 31, 2003	56,584	858,694	187,875	(25,106)	1,078,047
Common Stock Dividends			(99,293)		(99,293)
Preferred Stock Dividends			(340)		(340)
Capital Stock Expense		141	(134)		7
TOTAL					978,421
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,314				(4,298)	(4,298)
Minimum Pension Liability, Net of Tax of $8,533				(15,847)	(15,847)
NET INCOME			133,222		133,222
TOTAL COMPREHENSIVE INCOME					113,077
DECEMBER 31, 2004	$ 56,584	$ 858,835	$ 221,330	$ (45,251)	$ 1,091,498

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 3,122,883	$ 2,878,051
Transmission	1,009,551	1,000,926
Distribution	990,826	958,966
General (including nuclear fuel)	275,622	274,283
Construction Work in Progress	163,515	193,956
Total	5,562,397	5,306,182
Accumulated Depreciation and Amortization	2,603,479	2,490,912
TOTAL - NET	2,958,918	2,815,270
OTHER PROPERTY AND INVESTMENTS		
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,053,439	982,394
Nonutility Property, Net	50,440	52,303
Other Investments	21,848	43,797
TOTAL	1,125,727	1,078,494
CURRENT ASSETS		
Cash and Cash Equivalents	465	3,899
Other Cash Deposits	46	15
Advances to Affiliates	5,093	-
Accounts Receivable:		
Customers	62,608	63,084
Affiliated Companies	124,134	124,826
Miscellaneous	4,339	4,498
Allowance for Uncollectible Accounts	(187)	(531)
Fuel	27,218	33,968
Materials and Supplies	103,342	85,615
Risk Management Assets	52,141	44,071
Margin Deposits	5,400	7,245
Prepayments and Other	10,541	10,673
TOTAL	395,140	377,363
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	147,167	151,973
Incremental Nuclear Refueling Outage Expenses, Net	44,244	57,326
Unamortized Loss on Reacquired Debt	21,039	18,424
DOE Decontamination Fund	14,215	18,863
Other	31,015	29,691
Long-term Risk Management Assets	52,256	43,768
Emission Allowances	27,093	19,713
Deferred Property Taxes	22,372	21,916
Deferred Charges and Other Assets	28,955	26,270
TOTAL	388,356	387,944
TOTAL ASSETS	$ 4,868,141	$ 4,659,071

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	$ 56,584	$ 56,584
Paid-in Capital	858,835	858,694
Retained Earnings	221,330	187,875
Accumulated Other Comprehensive Income (Loss)	(45,251)	(25,106)
Total Common Shareholder's Equity	1,091,498	1,078,047
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,084	8,101
Total Shareholders' Equity	1,099,582	1,086,148
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	-	63,445
Long-term Debt	1,312,843	1,134,359
TOTAL	2,412,425	2,283,952
CURRENT LIABILITIES		
Cumulative Preferred Stock Due Within One Year	61,445	-
Long-term Debt Due Within One Year	-	205,000
Advances from Affiliates	-	98,822
Accounts Payable:		
General	91,472	101,776
Affiliated Companies	51,066	47,484
Customer Deposits	29,366	21,955
Taxes Accrued	123,159	42,189
Interest Accrued	12,465	17,963
Risk Management Liabilities	47,174	31,898
Obligations Under Capital Leases	6,124	6,528
Other	70,237	57,675
TOTAL	492,508	631,290
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	315,730	337,376
Regulatory Liabilities:		
Asset Removal Costs	280,054	263,015
Deferred Investment Tax Credits	82,802	90,278
Excess ARO for Nuclear Decommissioning	245,175	215,715
Unrealized Gain on Forward Commitments	35,534	25,010
Other	33,695	36,258
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	66,472	70,179
Long-term Risk Management Liabilities	36,815	33,537
Obligations Under Capital Leases	44,608	31,315
Asset Retirement Obligations	711,769	553,219
Employee Benefits and Pension Obligations	70,027	45,751
Deferred Credits and Other	40,527	42,176
TOTAL	1,963,208	1,743,829
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 4,868,141	$ 4,659,071

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 133,222	$ 86,388	$ 73,992
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Asset Impairments	-	10,300	-
Cumulative Effect of Accounting Change	-	3,160	-
Depreciation and Amortization	172,099	171,281	168,070
Accretion Expense	39,825	37,150	-
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	13,082	(27,754)	(26,577)
Unrecovered Fuel and Purchased Power Costs	(1,689)	37,501	37,501
Amortization of Nuclear Outage Costs	-	40,000	40,000
Deferred Income Taxes	(5,548)	(14,894)	(16,921)
Deferred Investment Tax Credits	(7,476)	(7,431)	(7,740)
Deferred Property Taxes	(456)	355	1,997
Mark-to-Market of Risk Management Contracts	2,756	43,938	(9,517)
Change in Other Noncurrent Assets	(4,799)	(22,283)	(30,397)
Change in Other Noncurrent Liabilities	(9,194)	(38,720)	9,196
Changes in Components of Working Capital:			
Accounts Receivable, Net	983	34,346	(106,683)
Fuel, Materials and Supplies	(10,977)	(7,320)	(2,084)
Accounts Payable	(6,722)	(69,396)	87,934
Taxes Accrued	80,970	(29,370)	1,798
Customer Deposits	7,411	5,294	7,391
Interest Accrued	(5,498)	(3,518)	790
Other Current Assets	1,977	(6,019)	(5,403)
Other Current Liabilities	12,157	(20,187)	4,887
Net Cash Flows From Operating Activities	412,123	222,821	228,234
INVESTING ACTIVITIES			
Construction Expenditures	(176,795)	(184,587)	(167,484)
Changes in Other Cash Deposits, Net	(31)	(28)	10,112
Proceeds from Sale of Assets	2,788	1,836	-
Other	-	-	1,759
Net Cash Flows Used For Investing Activities	(174,038)	(182,779)	(155,613)
FINANCING ACTIVITIES			
Capital Contributions from Parent	-	-	125,000
Issuance of Long-term Debt – Nonaffiliated	268,057	64,434	288,732
Retirement of Cumulative Preferred Stock	(2,011)	(1,500)	(424)
Retirement of Long-term Debt	(304,017)	(350,000)	(340,000)
Changes in Advances to/from Affiliates, Net	(103,915)	290,048	(144,917)
Dividends Paid on Common Stock	(99,293)	(40,000)	-
Dividends Paid on Cumulative Preferred Stock	(340)	(2,375)	(4,467)
Net Cash Flows Used For Financing Activities	(241,519)	(39,393)	(76,076)
Net Increase (Decrease) in Cash and Cash Equivalents	(3,434)	649	(3,455)
Cash and Cash Equivalents at Beginning of Period	3,899	3,250	6,705
Cash and Cash Equivalents at End of Period	$ 465	$ 3,899	$ 3,250

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $70,988,000, $82,593,000 and $89,984,000 and for income taxes was $(2,244,000), $94,440,000 and $60,523,000 in 2004, 2003 and 2002, respectively. Noncash acquisitions under capital leases were $20,557,000, $0 and $1,023,000 in 2004, 2003 and 2002, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF PREFERRED STOCK
December 31, 2004 and 2003

PREFERRED STOCK:
$100 Par Value Per Share – Authorized 2,250,000 shares
$25 Par Value Per Share – Authorized 11,200,000 shares

Series	Call Price December 31, 2004 (a)	Number of Shares Redeemed Year Ended December 31, 2004	2003	2002	Shares Outstanding December 31, 2004	2004 (in thousands)	2003 (in thousands)
Not Subject to Mandatory Redemption - $100 Par:							
4.125%	$ 106.125	-	-	20	55,369	$ 5,537	$ 5,537
4.560%	102.000	-	-	-	14,412	1,441	1,441
4.120%	102.728	175	-	6,326	11,055	1,106	1,123
Total						$ 8,084	$ 8,101
Subject to Mandatory Redemption - $100 Par (b):							
5.900%		20,000	-	-	132,000	$ 13,200	$ 15,200
6.250%		-	-	-	192,500	19,250	19,250
6.300%		-	-	-	132,450	13,245	13,245
6.875%		-	15,000	-	157,500	15,750	15,750
Total						$ 61,445	$ 63,445

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
(b) All shares of each series subject to mandatory redemption were reacquired in January 2005.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
December 31, 2004 and 2003

	2004	2003
LONG-TERM DEBT:	(in thousands)	
First Mortgage Bonds	$ -	$ 54,725
Installment Purchase Contracts	311,230	310,676
Senior Unsecured Notes	772,712	747,873
Other Long-term Debt (a)	228,901	226,085
Less Portion Due Within One Year	-	(205,000)
Long-term Debt Excluding Portion Due Within One Year	$ 1,312,843	$ 1,134,359

(a) Represents a liability for SNF disposal including interest payable to the DOE. See "SNF Disposal" section of Note 7.

There are certain limitations on establishing additional liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of our affiliates.

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.200	2024 – February 1	$ -	$ 30,000
7.500	2024 – March 1	-	25,000
Unamortized Discount		-	(275)
Total		$ -	$ 54,725

Installment Purchase Contracts have been entered in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2004	2003
			(in thousands)	
City of Lawrenceburg, Indiana	(a)	2019 – October 1	$ 25,000	$ 25,000
	5.900	2019 – November 1	-	52,000
	(b)	2021 – November 1	52,000	-
City of Rockport, Indiana	(a)	2025 – April 1	40,000	40,000
	6.550	2025 – June 1	50,000	50,000
	(c)	2025 – June 1	50,000	50,000
	4.900 (d)	2025 – June 1	50,000	50,000
City of Sullivan, Indiana	5.950	2009 – May 1	-	45,000
	(e)	2009 – May 1	45,000	-
Unamortized Discount			(770)	(1,324)
Total			$ 311,230	$ 310,676

(a) Rate is an annual long-term fixed rate of 2.625% through October 1, 2006. After that date the rate may be a daily or weekly reset rate, commercial paper, auction or other long-term rate as designated by I&M (fixed rate bonds).

(b) In October 2004, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate on December 31, 2004 was 1.815%. The auction rate for 2004 ranged from 1.70% to 1.815% and averaged 1.73%.

(c) In 2001, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate for 2004 ranged from 0.93% to 1.70% and averaged 1.26%. The auction rate for 2003 ranged from 0.85% to 1.35% and averaged 1.05%.
(d) Rate is fixed until June 1, 2007 (term rate bonds).
(e) In October 2004, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate on December 31, 2004 was 1.75%. The auction rate for 2004 ranged from 1.45% to 1.75% and averaged 1.59%.

The terms of the installment purchase contracts require I&M to pay amounts sufficient for the cities to pay interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain generating plants. The fixed rate bonds due 2019 and 2025 are subject to mandatory tender for purchase on October 1, 2006. Consequently, the fixed rate bonds have been classified for repayment purposes in 2006. The term rate bonds due 2025 are subject to mandatory tender for purchase on the term maturity date (June 1, 2007). Accordingly, the term rate bonds have been classified for repayment purposes in 2007 (the term end date). Interest payments range from every 35 days to semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.875	2004 – July 1	$ -	$ 150,000
6.125	2006 – December 15	300,000	300,000
6.450	2008 – November 10	50,000	50,000
6.375	2012 – November 1	100,000	100,000
5.050	2014 – November 15	175,000	-
6.000	2032 – December 31	150,000	150,000
Unamortized Discount		(2,288)	(2,127)
Total		$ 772,712	$ 747,873

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount (in thousands)
2005	$ -
2006	365,000
2007	50,000
2008	50,000
2009	45,000
Later Years	805,901
Total Principal Amount	1,315,901
Unamortized Discount	(3,058)
Total	$ 1,312,843

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to I&M's consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and subsidiaries 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.

As discussed in Note 2 to the consolidated financial statements, the Company adopted 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 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 450,613	$ 416,470	$ 378,683	$ 379,025	$ 389,875
Operating Income	55,321	64,744	42,197	47,678	49,738
Interest Charges	29,470	28,620	26,836	27,361	31,045
Income Before Cumulative Effect of Accounting Change	25,905	33,464	20,567	21,565	20,763
Cumulative Effect of Accounting Change, Net of Tax	-	(1,134)	-	-	-
Net Income	25,905	32,330	20,567	21,565	20,763
BALANCE SHEETS DATA					
Electric Utility Plant	$ 1,361,547	$ 1,349,746	$ 1,295,619	$ 1,128,415	$ 1,103,064
Accumulated Depreciation and Amortization	398,455	381,876	373,638	360,319	338,270
Net Electric Utility Plant	$ 963,092	$ 967,870	$ 921,981	$ 768,096	$ 764,794
Total Assets	$ 1,243,247	$ 1,221,634	$ 1,188,342	$ 1,022,833	$ 1,516,921
Common Shareholder's Equity	320,980	317,138	298,018	256,130	266,713
Long-term Debt (a)	508,310	487,602	466,632	346,093	330,880
Obligations Under Capital Leases (a)	4,363	5,292	7,248	9,583	14,184

(a) Including portion due within one year.

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

KPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 175,000 retail customers in our service territory in eastern Kentucky. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

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

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

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

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 the new environment. We are confident in our ability to participate successfully in the PJM market.

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

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

Net Income for 2004 decreased $6 million over the prior year primarily due to increases in planned boiler overhaul outages and administrative and support expenses.

2004 Compared to 2003

Operating Income

Operating Income for 2004 decreased by $9 million from 2003 primarily due to:

- A $25 million increase in Fuel for Electric Generation expenses resulting from an increase in the cost of coal consumed and a 6% increase in electric generation.
- An $8 million increase in Purchased Energy for Resale expenses primarily related to coal trading purchases from procurement contracts.
- A $5 million increase in Maintenance expense caused by planned boiler overhaul outages in the first and second quarters of 2004 as well as a turbine repair outage in the fourth quarter of 2004.
- A $5 million increase in Depreciation and Amortization expense primarily related to the installation of emission control equipment at the Big Sandy plant in mid-2003.
- A $4 million increase in Other Operation expense resulting from increased administrative and support expenses in 2004.

The decrease in Operating Income for 2004 was partially offset by:

- A $32 million increase in Electric Generation, Transmission and Distribution revenues due primarily to an improvement in commercial and industrial sales, the rate increase in mid-2003 to recover the cost of emission control equipment, increased fuel recoveries related to increased fuel costs, and increased revenues related to coal trading sales.
- A $3 million decrease in Income Taxes. See Income Taxes section below for further discussion.
- A $2 million increase in Sales to AEP Affiliates reflecting recovery of increased generation expenses.

Other Impacts on Earnings

Nonoperating Income increased $5 million in 2004 compared to 2003 primarily due to favorable results from risk management activities.

Nonoperating Income Tax Credit decreased $2 million in 2004 compared to 2003. See Income Taxes section below for further discussion.

Income Taxes

The effective tax rates for 2004 and 2003 were 25.1% and 22.4%, 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, amortization of investment tax credits, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is primarily due to less favorable federal income tax adjustments.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

Summary Obligation Information

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

Payment 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)	$ -	$ 383.0	$ 30.0	$ 95.0	$ 508.0
Capital Lease Obligations (b)	1.9	2.2	0.7	0.1	4.9
Noncancelable Operating Leases (b)	1.5	2.1	1.3	1.8	6.7
Fuel Purchase Contracts (c)	84.7	159.6	3.9	-	248.2
Energy and Capacity Purchase Contracts (d)	5.1	7.6	-	-	12.7
Total	$ 93.2	$ 554.5	$ 35.9	$ 96.9	$ 780.5

(a) See Schedule of Long-term Debt. Represents principal only excluding interest.
(b) See Note 15.
(c) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(d) Represents contractual cash flows of energy and capacity purchase contracts.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

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

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

Total MTM Risk Management Contract Net Assets at December 31, 2003	$	15,490
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(5,611)
Fair Value of New Contracts When Entered During the Period (b)		-
Net Option Premiums Paid/(Received) (c)		(106)
Change in Fair Value Due to Valuation Methodology Changes (d)		-
Changes in Fair Value of Risk Management Contracts (e)		496
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)		2,422
Total MTM Risk Management Contract Net Assets		12,691
Net Cash Flow and Fair Value Hedge Contracts (g)		1,102
DETM Assignment (h)		(5,570)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$	8,223

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.
(b) "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 that were 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 Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See "AEP East Companies" in Note 17.

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

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 15,691	$ 4,154	$ -	$ 19,845
Noncurrent Assets	19,063	4	-	19,067
Total MTM Derivative Contract Assets	34,754	4,158	-	38,912
Current Liabilities	(11,784)	(2,697)	(2,724)	(17,205)
Noncurrent Liabilities	(10,279)	(359)	(2,846)	(13,484)
Total MTM Derivative Contract Liabilities	(22,063)	(3,056)	(5,570)	(30,689)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 12,691	$ 1,102	$ (5,570)	$ 8,223

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "AEP East Companies" in Note 17.
(c) 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 Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of December 31, 2004
(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (1,107)	$ (40)	$ 557	$ -	$ -	$ -	$ (590)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	5,236	2,133	1,882	676	-	-	9,927
Prices Based on Models and Other Valuation Methods (b)	(222)	(223)	(233)	1,027	1,464	1,541	3,354
Total	$ 3,907	$ 1,870	$ 2,206	$ 1,703	$ 1,464	$ 1,541	$ 12,691

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in 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 are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow and Fair Value Hedges.

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 operations. We monitor these risks on our future operations and may employ various commodity instruments 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.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges 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. In accordance with GAAP, all amounts are presented net of related income taxes.

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

	Power	Interest Rate	Total
Beginning Balance December 31, 2003	$ 82	$ 338	$ 420
Changes in Fair Value (a)	918	-	918
Reclassifications from AOCI to Net Income (b)	(431)	(94)	(525)
Ending Balance December 31, 2004	$ 569	$ 244	$ 813

(a) "Changes in Fair Value" shows 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.
(b) "Reclassifications from AOCI to Net Income" represents 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.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $800 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

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

December 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$135	$442	$191	$65	$136	$527	$220	$52

VaR Associated with Debt Outstanding

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 $16 million and $29 million at December 31, 2004 and 2003, respectively. 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 negatively affect our results of operations or financial position.

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 409,023	$ 376,662	$ 350,719
Sales to AEP Affiliates	41,590	39,808	27,964
TOTAL	450,613	416,470	378,683
OPERATING EXPENSES			
Fuel for Electric Generation	99,456	74,148	65,043
Purchased Energy for Resale	8,532	963	29
Purchased Electricity from AEP Affiliates	140,758	141,690	133,002
Other Operation	51,757	47,325	52,892
Maintenance	32,802	27,328	35,089
Depreciation and Amortization	43,847	39,309	33,233
Taxes Other Than Income Taxes	9,145	8,788	8,240
Income Taxes	8,995	12,175	8,958
TOTAL	395,292	351,726	336,486
OPERATING INCOME	55,321	64,744	42,197
Nonoperating Income (Loss)	1,298	(4,036)	7,950
Nonoperating Expenses	1,568	1,124	840
Nonoperating Income Tax Expense (Credit)	(324)	(2,500)	1,904
Interest Charges	29,470	28,620	26,836
Income Before Cumulative Effect of Accounting Change	25,905	33,464	20,567
Cumulative Effect of Accounting Change, Net of Tax	-	(1,134)	-
NET INCOME	$ 25,905	$ 32,330	$ 20,567

The common stock of KPCo is wholly-owned by AEP

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 50,450	$ 158,750	$ 48,833	$ (1,903)	$ 256,130
Capital Contribution from Parent		50,000			50,000
Common Stock Dividends			(21,131)		(21,131)
TOTAL					284,999
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,198				2,225	2,225
Minimum Pension Liability, Net of Tax of $5,262				(9,773)	(9,773)
NET INCOME			20,567		20,567
TOTAL COMPREHENSIVE INCOME					13,019
DECEMBER 31, 2002	50,450	208,750	48,269	(9,451)	298,018
Common Stock Dividends			(16,448)		(16,448)
TOTAL					281,570
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $53				98	98
Minimum Pension Liability, Net of Tax of $1,691				3,140	3,140
NET INCOME			32,330		32,330
TOTAL COMPREHENSIVE INCOME					35,568
DECEMBER 31, 2003	50,450	208,750	64,151	(6,213)	317,138
Common Stock Dividends			(19,501)		(19,501)
TOTAL					297,637
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $212				393	393
Minimum Pension Liability, Net of Tax of $1,592				(2,955)	(2,955)
NET INCOME			25,905		25,905
TOTAL COMPREHENSIVE INCOME					23,343
DECEMBER 31, 2004	$ 50,450	$ 208,750	$ 70,555	$ (8,775)	$ 320,980

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 462,641	$ 457,341
Transmission	385,667	381,354
Distribution	438,766	425,688
General	57,929	68,041
Construction Work in Progress	16,544	17,322
Total	1,361,547	1,349,746
Accumulated Depreciation and Amortization	398,455	381,876
TOTAL – NET	963,092	967,870
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	5,438	5,423
Other Investments	422	1,022
TOTAL	5,860	6,445
CURRENT ASSETS		
Cash and Cash Equivalents	127	863
Other Cash Deposits	5	23
Advances to Affiliates	16,127	-
Accounts Receivable:		
Customers	22,130	21,177
Affiliated Companies	23,046	25,327
Accrued Unbilled Revenues	7,340	5,534
Miscellaneous	94	97
Allowance for Uncollectible Accounts	(34)	(736)
Fuel	6,551	9,481
Materials and Supplies	9,385	8,831
Risk Management Assets	19,845	16,200
Margin Deposits	1,960	2,660
Prepayments and Other	1,782	1,696
TOTAL	108,358	91,153
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	103,849	99,828
Other	14,558	13,971
Long-term Risk Management Assets	19,067	16,134
Emission Allowances	9,666	7,754
Deferred Property Taxes	7,036	6,847
Deferred Charges and Other	11,761	11,632
TOTAL	165,937	156,166
TOTAL ASSETS	$ 1,243,247	$ 1,221,634

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $50 Par Value Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	$ 50,450	$ 50,450
Paid-in Capital	208,750	208,750
Retained Earnings	70,555	64,151
Accumulated Other Comprehensive Income (Loss)	(8,775)	(6,213)
Total Common Shareholder's Equity	320,980	317,138
Long-term Debt:		
Nonaffiliated	428,310	427,602
Affiliated	80,000	60,000
Total Long-term Debt	508,310	487,602
TOTAL	829,290	804,740
CURRENT LIABILITIES		
Accounts Payable:		
General	20,080	22,802
Affiliated Companies	24,899	22,648
Advances from Affiliates	-	38,096
Risk Management Liabilities	17,205	11,704
Taxes Accrued	9,248	7,329
Interest Accrued	6,754	6,915
Customer Deposits	12,309	9,894
Obligations Under Capital Leases	1,561	1,743
Other	9,038	8,628
TOTAL	101,094	129,759
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	227,536	212,121
Regulatory Liabilities:		
Asset Removal Costs	28,232	26,140
Deferred Investment Tax Credits	6,722	7,955
Other Regulatory Liabilities	15,622	10,591
Employee Benefits and Pension Obligations	17,729	13,999
Long-term Risk Management Liabilities	13,484	12,363
Obligations Under Capital Leases	2,802	3,549
Deferred Credits	736	417
TOTAL	312,863	287,135
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 1,243,247	$ 1,221,634

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 25,905	$ 32,330	$ 20,567
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Changes	-	1,134	-
Depreciation and Amortization	43,847	39,309	33,233
Deferred Income Taxes	12,774	20,107	9,839
Deferred Investment Tax Credits	(1,233)	(1,210)	(1,240)
Deferred Property Taxes	(189)	(547)	(338)
Deferred Fuel Costs, Net	1,164	233	2,998
Mark-to-Market of Risk Management Contracts	1,020	15,112	(12,267)
Change in Other Noncurrent Assets	(7,269)	(15,184)	(22,187)
Change in Other Noncurrent Liabilities	8,147	6,224	(5,898)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(1,177)	2,445	(9,332)
Fuel, Materials and Supplies	2,376	2,250	3,170
Accounts Payable	(471)	(45,100)	44,529
Taxes Accrued	1,919	8,582	(11,558)
Customer Deposits	2,415	1,846	3,588
Interest Accrued	(161)	444	1,202
Other Current Assets	614	(2,229)	(812)
Other Current Liabilities	226	(3,949)	16,827
Net Cash Flows From Operating Activities	89,907	61,797	72,321
INVESTING ACTIVITIES			
Construction Expenditures	(38,475)	(81,707)	(178,700)
Change in Other Cash Deposits, Net	18	(4)	17
Proceeds from Sale of Assets	1,538	967	-
Other	-	-	217
Net Cash Flows Used For Investing Activities	(36,919)	(80,744)	(178,466)
FINANCING ACTIVITIES			
Capital Contributions from Parent	-	-	50,000
Issuance of Long-term Debt – Nonaffiliated	-	74,263	-
Issuance of Long-term Debt – Affiliated	20,000	-	274,964
Retirement of Long-term Debt – Nonaffiliated	-	(40,000)	(154,500)
Retirement of Long-term Debt – Affiliated	-	(15,000)	-
Change in Advances to/from Affiliates, Net	(54,223)	14,710	(42,814)
Dividends Paid	(19,501)	(16,448)	(21,131)
Net Cash Flows From (Used For) Financing Activities	(53,724)	17,525	106,519
Net Increase (Decrease) in Cash and Cash Equivalents	(736)	(1,422)	374
Cash and Cash Equivalents at Beginning of Period	863	2,285	1,911
Cash and Cash Equivalents at End of Period	$ 127	$ 863	$ 2,285

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $28,367,000, $26,988,000 and $25,176,000 in 2004, 2003 and 2002, respectively. Cash paid (received) for income taxes was $(3,233,000), $(17,574,000) and $13,041,000 in 2004, 2003 and 2002, respectively. Noncash acquisitions under capital leases were $925,000, $0 and $22,000 in 2004, 2003 and 2002, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
SCHEDULE OF LONG-TERM DEBT
December 31, 2004 and 2003

	2004	2003
	(in thousands)	
LONG-TERM DEBT:		
Senior Unsecured Notes	$ 428,310	$ 427,602
Notes Payable - Affiliated	80,000	60,000
Long-term Debt Excluding Portion Due Within One Year	$ 508,310	$ 487,602

There are certain limitations on establishing liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.910	2007 – October 1	$ 48,000	$ 48,000
6.450	2008 – November 10	30,000	30,000
5.500	2007 – July 1	125,000	125,000
4.310	2007 – November 12	80,400	80,400
4.370	2007 – December 12	69,564	69,564
5.625	2032 – December 31	75,000	75,000
Unamortized Discount		(268)	(362)
Interest Rate Hedge		614	-
Total		$ 428,310	$ 427,602

Notes Payable to Parent were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.501	2006 – May 15	$ 60,000	$ 60,000
5.250	2015 – June 1	20,000	-
Total		$ 80,000	$ 60,000

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ -
2006	60,000
2007	322,964
2008	30,000
2009	-
Later Years	95,000
Total Principal Amount	507,964
Unamortized Discount	(268)
Interest Rate Hedge	614
Total	$ 508,310

KENTUCKY POWER COMPANY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to KPCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to KPCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying balance sheets of Kentucky Power Company as of December 31, 2004 and 2003, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2004 and 2003, and the results of its operations and its 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.

As discussed in Note 2 to the financial statements, the Company adopted 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 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 2,236,396	$ 2,244,653	$ 2,113,125	$ 2,098,105	$ 2,140,331
Operating Income	312,372	359,667	298,329	240,710	226,827
Interest Charges	118,685	106,464	83,682	93,603	119,210
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	210,116	251,031	220,023	165,793	102,613
Extraordinary Loss, Net of Tax	-	-	-	(18,348)	(18,876)
Cumulative Effect of Accounting Changes, Net of Tax	-	124,632	-	-	-
Net Income	210,116	375,663	220,023	147,445	83,737
BALANCE SHEETS DATA					
Electric Utility Plant	$ 6,798,032	$ 6,513,591	$ 5,685,826	$ 5,390,576	$ 5,577,631
Accumulated Depreciation and Amortization	2,617,238	2,485,947	2,469,837	2,360,857	2,678,606
Net Electric Utility Plant	$ 4,180,794	$ 4,027,644	$ 3,215,989	$ 3,029,719	$ 2,899,025
TOTAL ASSETS (b)	$ 5,593,265	$ 5,374,518	$ 4,554,023	$ 4,485,787	$ 6,279,499
Common Shareholder's Equity	1,473,838	1,464,025	1,233,114	1,184,785	1,181,770
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,641	16,645	16,648	16,648	16,648
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	5,000	7,250	8,850	8,850	8,850
Long-term Debt (a)(b)	2,011,060	2,039,940	1,067,314	1,203,841	1,195,493
Obligations Under Capital Leases (a)	40,733	34,688	65,626	80,666	116,581

(a) Including portion due within one year.
(b) Due to the implementation of FIN 46, OPCo was required to consolidate JMG during the third quarter of 2003.

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

OPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 707,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio. We consolidate JMG Funding LP, a variable interest entity. As a member of the AEP Power Pool, we share in the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers.

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

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated 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 via the AEP Power Pool, discussed above.

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 the new environment. We are confident in our ability to participate successfully in the PJM market.

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

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Effective July 1, 2003, we consolidated JMG as a result of the implementation of FIN 46. OPCo records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. While there was no effect to net income as a result of consolidation, some individual income statement captions were affected. See "FIN 46 Consolidation of Variable Interest Entities" section of Note 2 and "Gavin Scrubber Financing Arrangement" section of Note 15.

Results of Operations

During 2004, Net Income decreased by $166 million primarily due to a $125 million Cumulative Effect of Accounting Changes recorded in the first quarter of 2003. Income Before Cumulative Effect decreased $41 million primarily due to an increase in fuel cost for electric generation.

During 2003, Net Income increased $156 million including a $125 million Cumulative Effect of Accounting Changes in the first quarter of 2003 (see "Cumulative Effect of Accounting Change" section of Note 2). Income Before Cumulative Effect of Accounting Changes increased $31 million primarily due to increased revenues which were allocated to us from sales made to third parties by the AEP Power Pool.

2004 Compared to 2003

Operating Income

Operating Income decreased by $47 million primarily due to:

- A $29 million increase in fuel expense related to a 7% increase in the cost of coal consumed. The effect of this increase in price was partially offset by a 2.5% decrease in net generation.
- A $29 million increase in Depreciation and Amortization expense primarily associated with the consolidation of JMG (there was no change in Net Income due to the consolidation of JMG). In addition, the increase is a result of a greater depreciable asset base in 2004, including capitalized software costs and the increased amortization of transition generation regulatory assets due to normal operating adjustments.
- A $23 million decrease in nonaffiliated wholesale energy sales and related transmission services due to lower sales volume.
- An $18 million increase in Other Operation expense primarily related to increased employee benefit expense including pension plan costs and workers' compensation and administrative and support expenses.
- An $11 million increase in Maintenance expense primarily associated with costs incurred as a result of a major ice storm in December 2004.
- A $3 million decrease in Sales to AEP Affiliates due to lower sales volume.

The decrease in Operating Income was partially offset by:

- A $49 million decrease in Income Taxes. See Income Taxes section below for further discussion.
- A $15 million increase in operating revenues related to favorable results from risk management activities.
- A $7 million increase in retail electric revenues resulting from increased demand of industrial customers due to the recovering economy.

Other Impacts on Earnings

Nonoperating Income increased $146 million primarily due to sales of excess energy purchased from the Dow Chemical Company (Dow) at the Plaquemine, Louisiana plant (see "Power Generation Facility" section below) including the effects of a related affiliate agreement which eliminates our market exposure related to the purchases from Dow. There was no change in Net Income due to the agreement with Dow. In addition, income from nonoperating risk management activities contributed to this increase.

Nonoperating Expenses increased $120 million primarily due to the agreement to purchase excess energy from Dow at the Plaquemine, Louisiana plant (see "Power Generation Facility" section below). There was no change in Net Income due to the agreement with Dow.

Interest Charges increased $12 million due to the consolidation of JMG in July 2003 and its associated debt. There was no change in Net Income due to the consolidation of JMG.

Income Taxes

The effective tax rates for 2004 and 2003 were 31.4% and 35.5%, 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, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes, and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to lower state income taxes and more favorable federal income tax adjustments.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes during 2003 of $125 million is due to the one-time after tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

2003 Compared to 2002

Operating Income

Operating Income increased $61 million due to:

- A $47 million decrease in Other Operation expense. This decrease was primarily due to a $23 million decrease in rent expense associated with the OPCo consolidation of JMG. OPCo now records the depreciation, interest and other expenses of JMG and eliminates operating lease expense against JMG's lease revenues. There was no change in Net Income due to the consolidation of JMG. In addition, operating expenses decreased due to a $7 million pretax adjustment to the workers' compensation reserve related to coal companies sold in July 2001, a $9 million decrease in expense related to post-employment benefits and an $8 million reduction in employee salary expenses.
- A $22 million increase in revenues from nonaffiliated off-system sales and a $119 million increase in Sales to AEP Affiliates. The increase in nonaffiliated off-system sales is primarily the result of an 8.9% increase in the price per MWH in 2003. The increase in affiliated sales is the result of optimizing our generation capacity and selling our excess power to the AEP Power Pool.

The increase in Operating Income was partially offset by:

- A $32 million increase in Fuel for Electric Generation as a result of a 9.7% increase in MWH generated.
- A $32 million increase in Income Taxes. See Income Taxes section below for further discussion.
- A $30 million increase in Maintenance expenses. The increase in 2003 is primarily due to increased boiler overhaul costs for planned and forced outages coupled with increased expense in maintaining overhead lines due to storm damage in southern Ohio.
- A $20 million increase in Purchased Electricity from AEP Affiliates resulting from a 31% volume increase in MWHs purchased from the AEP Power Pool.
- An increase in Depreciation and Amortization associated with the OPCo consolidation of JMG. Effective July 1, 2003, depreciation expense related to the assets owned by JMG is consolidated with OPCo.

Other Impacts on Earnings

Nonoperating Income decreased $34 million for the year 2003 compared to 2002 primarily due to unfavorable results from risk management activities.

Nonoperating Income Tax Expense decreased $26 million as a result of a decrease in pretax nonoperating book income and changes related to consolidated tax savings.

Interest charges increased $23 million due primarily to the consolidation of JMG and its associated debt along with replacement of lower cost floating-rate short-term debt with higher cost fixed-rate longer-term debt.

Income Taxes

The effective tax rates for 2003 and 2002 were 35.5% and 37.4%, 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, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes, and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time after tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	A3	BBB	BBB+

Cash Flow

Cash flows for the years ended December 31, 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(in thousands)	
Cash and cash equivalents at beginning of period	$ 7,233	$ 5,275	$ 6,727
Cash flows from (used for):			
Operating activities	563,107	373,443	478,973
Investing activities	(291,589)	(288,018)	(346,187)
Financing activities	(269,451)	(83,467)	(134,238)
Net increase (decrease) in cash and cash equivalents	2,067	1,958	(1,452)
Cash and cash equivalents at end of period	$ 9,300	$ 7,233	$ 5,275

Operating Activities

Our net cash flows from operating activities were $563 million in 2004. We produced income of $210 million during the period and a noncash expense item of $286 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $100 million change in Taxes Accrued. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP 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.

Our net cash flows from operating activities were $373 million in 2003. We produced income of $376 million during the period and noncash expense items of $257 million for Depreciation and Amortization and $(125) million for Cumulative Effect of Accounting Changes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $(173) million change in Accounts Payable, net. The change is a result of significant reductions of accounts payable balances partially associated with a wind down of risk management activities during 2003.

Our net cash flows from operating activities were $479 million in 2002. We produced income of $220 million during the period and noncash expense items of $249 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; none of which were significant.

Investing Activities

Our net cash flows used for investing activities in 2004 were $292 million primarily due to Construction Expenditures of $345 million. Current year construction expenditures were focused primarily on projects to improve service reliability for transmission and distribution, as well as environmental upgrades.

Our net cash flows used for investing activities in 2003 were $288 million primarily due to Construction Expenditures of $250 million. The construction expenditures are primarily due to improving the service reliability for transmission and distribution, as well as environmental upgrades.

Our net cash flows used for investing activities in 2002 were $346 million primarily due to Construction Expenditures of $355 million.

Financing Activities

Our net cash flows used for financing activities in 2004 were $269 million primarily due to retirement of long-term debt and payment of dividends on common stock offset by a long-term debt issuance from AEP.

Our net cash flows used for financing activities in 2003 were $83 million due to replacing both short and long-term debt with proceeds from new borrowings.

Our net cash flows used for financing activities in 2002 were $134 million due to decreased borrowings from the Utility Money Pool, retirement of long-term debt and payment of dividends on common stock offset by short-term debt borrowings.

In January 2005, we refinanced $218 million of JMG's Installment Purchase Contracts. The new bonds bear interest at a 35-day auction rate.

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:

Payment 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)	$ 12.4	$ 230.2	$ 132.7	$ 1,642.1	$ 2,017.4
Short-term Debt	23.5	-	-	-	23.5
Cumulative Preferred Stock Subject to Mandatory Redemption (b)	5.0	-	-	-	5.0
Capital Lease Obligations (c)	9.8	16.4	8.5	20.3	55.0
Noncancelable Operating Leases (c)	16.2	29.5	27.3	71.9	144.9
Fuel Purchase Contracts (d)	585.3	881.2	396.2	431.3	2,294.0
Energy and Capacity Purchase Contracts (e)	16.0	23.7	-	-	39.7
Total	$ 668.2	$ 1,181.0	$ 564.7	$ 2,165.6	$ 4,579.5

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.
(b) See Schedule of Preferred Stock.
(c) See Note 15.
(d) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(e) Represents contractual cash flows of energy and capacity purchase contracts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2004 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)	$ -	$ 50.6	$ -	$ -	$ 50.6

(a) We have issued standby letters of credit to third parties. These letters of credit cover 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 $50.6 million maturing in December 2006. There is no recourse to third parties in the event these letters of credit are drawn.

Other

Power Generation Facility

AEP has 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 AEP. AEP has 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.

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 OPCo separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. OPCo alleges that TEM has breached the PPA, and is seeking a determination of OPCo's 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 OPCo's breaches. If the PPA is deemed terminated or found to be unenforceable by the court, OPCo could be adversely affected to the extent it is unable to find other purchasers of the power with similar contractual terms and to the extent OPCo does not fully recover claimed termination value damages from TEM. However, OPCo has entered into an agreement with an affiliate that eliminates OPCo's market exposure related to the PPA. 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 OPCo partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA. The litigation is now 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.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

Roll-Forward of MTM Risk Management Contract Net Assets

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

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

Total MTM Risk Management Contract Net Assets at December 31, 2003	$ 53,938
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(27,453)
Fair Value of New Contracts When Entered During the Period (b)	3,481
Net Option Premiums Paid/(Received) (c)	(363)
Change in Fair Value Due to Valuation Methodology Changes (d)	1,189
Changes in Fair Value of Risk Management Contracts (e)	16,985
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	47,777
Net Cash Flow Hedge Contracts (g)	984
DETM Assignment (h)	(19,065)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 29,696

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.
(b) "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 that were 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 Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See "AEP East Companies" in Note 17.

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

	MTM Risk Management Contracts (a)	Cash Flow Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 66,053	$ 13,488	$ -	$ 79,541
Noncurrent Assets	66,712	15	-	66,727
Total MTM Derivative Contract Assets	132,765	13,503	-	146,268
Current Liabilities	(49,249)	(11,739)	(9,323)	(70,311)
Noncurrent Liabilities	(35,739)	(780)	(9,742)	(46,261)
Total MTM Derivative Contract Liabilities	(84,988)	(12,519)	(19,065)	(116,572)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 47,777	$ 984	$ (19,065)	$ 29,696

(a) Does not include Cash Flow Hedges.
(b) See "AEP East Companies" in Note 17.
(c) 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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 Fair Value of Contracts as of December 31, 2004 (in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (3,790)	$ (137)	$ 1,906	$ -	$ -	$ -	$ (2,021)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	21,296	7,499	7,133	2,313	-	-	38,241
Prices Based on Models and Other Valuation Methods (b)	(702)	(735)	(810)	3,515	5,013	5,276	11,557
Total	$ 16,804	$ 6,627	$ 8,229	$ 5,828	$ 5,013	$ 5,276	$ 47,777

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in 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 are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

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 operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price 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 table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges 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. In accordance with GAAP, all amounts are presented net of related income taxes.

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

	Power	Foreign Currency	Total
Beginning Balance December 31, 2003	$ 268	$ (371)	$ (103)
Changes in Fair Value (a)	2,830	-	2,830
Reclassifications from AOCI to Net Income (b)	(1,499)	13	(1,486)
Ending Balance December 31, 2004	$ 1,599	$ (358)	$ 1,241

(a) "Changes in Fair Value" shows 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.
(b) "Reclassifications from AOCI to Net Income" represents 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.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2,083 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

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

December 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$464	$1,513	$652	$223	$444	$1,724	$722	$172

VaR Associated with Debt Outstanding

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 $146 million and $214 million at December 31, 2004 and 2003, respectively. 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 negatively affect our results of operations or consolidated financial position.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,654,881	$ 1,660,375	$ 1,647,923
Sales to AEP Affiliates	581,515	584,278	465,202
TOTAL	2,236,396	2,244,653	2,113,125
OPERATING EXPENSES			
Fuel for Electric Generation	645,292	616,680	584,730
Purchased Energy for Resale	64,229	63,486	67,385
Purchased Electricity from AEP Affiliates	89,355	90,821	71,154
Other Operation	386,732	369,087	416,533
Maintenance	177,584	166,438	136,609
Depreciation and Amortization	286,300	257,417	248,557
Taxes Other Than Income Taxes	177,374	175,043	176,247
Income Taxes	97,158	146,014	113,581
TOTAL	1,924,024	1,884,986	1,814,796
OPERATING INCOME	312,372	359,667	298,329
Nonoperating Income	170,128	24,495	58,289
Nonoperating Expenses	154,747	34,282	34,903
Nonoperating Income Tax Expense (Credit)	(1,048)	(7,615)	18,010
Interest Charges	118,685	106,464	83,682
Income Before Cumulative Effect of Accounting Changes	210,116	251,031	220,023
Cumulative Effect of Accounting Changes, Net of Tax	-	124,632	-
NET INCOME	210,116	375,663	220,023
Preferred Stock Dividend Requirements	733	1,098	1,258
EARNINGS APPLICABLE TO COMMON STOCK	$ 209,383	$ 374,565	$ 218,765

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 321,201	$ 462,483	$ 401,297	$ (196)	$ 1,184,785
Common Stock Dividends			(97,746)		(97,746)
Preferred Stock Dividends			(1,258)		(1,258)
TOTAL					1,085,781
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $292				(542)	(542)
Minimum Pension Liability, Net of Tax of $38,849				(72,148)	(72,148)
NET INCOME			220,023		220,023
TOTAL COMPREHENSIVE INCOME					147,333
DECEMBER 31, 2002	321,201	462,483	522,316	(72,886)	1,233,114
Common Stock Dividends			(167,734)		(167,734)
Preferred Stock Dividends			(1,098)		(1,098)
Capital Stock Gains		1			1
TOTAL					1,064,283
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $342				635	635
Minimum Pension Liability, Net of Tax of $13,495				23,444	23,444
NET INCOME			375,663		375,663
TOTAL COMPREHENSIVE INCOME					399,742
DECEMBER 31, 2003	321,201	462,484	729,147	(48,807)	1,464,025
Common Stock Dividends			(174,114)		(174,114)
Preferred Stock Dividends			(733)		(733)
Capital Stock Gains		1			1
TOTAL					1,289,179
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $723				1,344	1,344
Minimum Pension Liability, Net of Tax of $14,432				(26,801)	(26,801)
NET INCOME			210,116		210,116
TOTAL COMPREHENSIVE INCOME					184,659
DECEMBER 31, 2004	$ 321,201	$ 462,485	$ 764,416	$ (74,264)	$ 1,473,838

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 4,127,284	$ 4,029,515
Transmission	978,492	938,805
Distribution	1,202,550	1,156,886
General	248,749	245,434
Construction Work in Progress	240,957	142,951
Total	6,798,032	6,513,591
Accumulated Depreciation and Amortization	2,617,238	2,485,947
TOTAL – NET	4,180,794	4,027,644
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	44,774	47,015
Other	13,409	22,179
TOTAL	58,183	69,194
CURRENT ASSETS		
Cash and Cash Equivalents	9,300	7,233
Other Cash Deposits	37	51,017
Advances to Affiliates	125,971	67,918
Accounts Receivable:		
Customers	98,951	100,960
Affiliated Companies	144,175	120,532
Accrued Unbilled Revenues	10,641	17,221
Miscellaneous	7,626	736
Allowance for Uncollectible Accounts	(93)	(789)
Fuel	70,309	77,725
Materials and Supplies	55,569	65,768
Emissions Allowances	95,303	2,085
Risk Management Assets	79,541	56,265
Margin Deposits	7,056	9,296
Prepayments and Other	10,492	15,883
TOTAL	714,878	591,850
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	169,866	169,605
Transition Regulatory Assets	225,273	310,035
Unamortized Loss on Reacquired Debt	11,046	10,172
Other	22,189	22,506
Long-term Risk Management Assets	66,727	52,825
Deferred Property Taxes	70,214	67,469
Deferred Charges and Other Assets	74,095	53,218
TOTAL	639,410	685,830
TOTAL ASSETS	$ 5,593,265	$ 5,374,518

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	$ 321,201	$ 321,201
Paid-in Capital	462,485	462,484
Retained Earnings	764,416	729,147
Accumulated Other Comprehensive Income (Loss)	(74,264)	(48,807)
Total Common Shareholder's Equity	1,473,838	1,464,025
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,641	16,645
Total Shareholders' Equity	1,490,479	1,480,670
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	-	7,250
Long-term Debt:		
Nonaffiliated	1,598,706	1,608,086
Affiliated	400,000	-
Total Long-term Debt	1,998,706	1,608,086
TOTAL	3,489,185	3,096,006
Minority Interest	14,083	16,314
CURRENT LIABILITIES		
Short-term Debt – Nonaffiliated	23,498	25,941
Long-term Debt Due Within One Year – Nonaffiliated	12,354	431,854
Cumulative Preferred Stock Subject to Mandatory Redemption	5,000	-
Accounts Payable:		
General	143,247	104,874
Affiliated Companies	116,615	101,758
Customer Deposits	22,620	17,308
Taxes Accrued	233,026	132,793
Interest Accrued	39,254	45,679
Risk Management Liabilities	70,311	38,318
Obligations Under Capital Leases	9,081	9,624
Other	74,977	71,642
TOTAL	749,983	979,791
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	943,465	933,582
Regulatory Liabilities:		
Asset Removal Costs	102,875	101,160
Deferred Investment Tax Credits	12,539	15,641
Other	-	3
Long-term Risk Management Liabilities	46,261	40,477
Deferred Credits	24,377	23,222
Employee Benefits and Pension Obligations	126,825	90,260
Obligations Under Capital Leases	31,652	25,064
Asset Retirement Obligations	45,606	42,656
Other	6,414	10,342
TOTAL	1,340,014	1,282,407
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,593,265	$ 5,374,518

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 210,116	$ 375,663	$ 220,023
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Changes	-	(124,632)	-
Depreciation and Amortization	286,300	257,417	248,557
Pension and Postemployment Benefits Reserves	32,637	(75,822)	110,298
Deferred Income Taxes	23,329	24,482	46,010
Deferred Investment Tax Credits	(3,102)	(3,107)	(3,177)
Deferred Property Tax	(2,745)	(848)	(1,803)
Mark-to-Market of Risk Management Contracts	1,171	60,064	(28,693)
Change in Other Noncurrent Assets	(8,077)	(23,241)	(12,963)
Change in Other Noncurrent Liabilities	(41,055)	40,048	(120,864)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(22,640)	(3,966)	17,652
Fuel, Materials and Supplies	(4,766)	7,271	7,740
Accounts Payable, Net	53,230	(173,218)	8,704
Taxes Accrued	100,233	21,015	(14,992)
Interest Accrued	(6,425)	21,533	1,130
Customer Deposits	5,312	4,339	7,517
Other Current Assets	(63,203)	(13,096)	8,783
Other Current Liabilities	2,792	(20,459)	(14,949)
Net Cash Flows From Operating Activities	563,107	373,443	478,973
INVESTING ACTIVITIES			
Construction Expenditures	(345,489)	(249,688)	(354,797)
Change in Other Cash Deposits, Net	50,980	(51,007)	2,111
Proceeds from Sale of Assets	2,920	12,671	-
Other	-	6	6,499
Net Cash Flows Used For Investing Activities	(291,589)	(288,018)	(346,187)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	-	988,914	-
Issuance of Long-term Debt – Affiliated	400,000	-	-
Change in Advances to/from Affiliates, Net	(58,053)	(197,897)	(170,234)
Change in Short-term Debt – Nonaffiliated, Net	(2,443)	(671)	-
Change in Short-term Debt – Affiliated, Net	-	(275,000)	275,000
Retirement of Long-term Debt – Nonaffiliated	(431,854)	(128,378)	(140,000)
Retirement of Long-term Debt – Affiliated	-	(300,000)	-
Retirement of Cumulative Preferred Stock	(2,254)	(1,603)	-
Dividends Paid on Common Stock	(174,114)	(167,734)	(97,746)
Dividends Paid on Cumulative Preferred Stock	(733)	(1,098)	(1,258)
Net Cash Flows Used For Financing Activities	(269,451)	(83,467)	(134,238)
Net Increase (Decrease) in Cash and Cash Equivalents	2,067	1,958	(1,452)
Cash and Cash Equivalents at Beginning of Period	7,233	5,275	6,727
Cash and Cash Equivalents at End of Period	$ 9,300	$ 7,233	$ 5,275

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $119,562,000, $77,170,000 and $81,041,000 and for income taxes was $(21,600,000), $98,923,000 and $105,058,000 in 2004, 2003 and 2002, respectively. Noncash acquisitions under capital leases were $14,727,000, $0 and $106,000 in 2004, 2003 and 2002, respectively. Noncash activity in 2003 included an increase in assets and liabilities of $469.6 million resulting from the consolidation of JMG (see Note 2).
See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
SCHEDULE OF PREFERRED STOCK
December 31, 2004 and 2003

	2004	2003
	(in thousands)	

PREFERRED STOCK:
$100 Par Value per share – Authorized 3,762,403 shares
$25 Par Value per share – Authorized 4,000,000 shares

Series	Call Price December 31, 2004 (a)	Number of Shares Redeemed Year Ended December 31, 2004	2003	2002	Shares Outstanding December 31, 2004	2004	2003
Not Subject to Mandatory Redemption - $100 Par:							
4.08%	$103.0	-	-	-	14,595	$ 1,460	$ 1,460
4.20%	103.2	-	-	-	22,824	2,282	2,282
4.40%	104.0	-	-	-	31,512	3,151	3,151
4.50%	110.0	41	23	-	97,482	9,748	9,752
Total						$ 16,641	$ 16,645
Subject to Mandatory Redemption - $100 Par:							
5.90%	$100.0	22,500	-	-	50,000 (b)	$ 5,000	$ 7,250

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
(b) All outstanding shares were redeemed on January 3, 2005.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
SCHEDULE OF CONSOLDIATED LONG-TERM DEBT
December 31, 2004 and 2003

	2004	2003
	(in thousands)	
LONG-TERM DEBT:		
First Mortgage Bonds	$ -	$ 9,950
Installment Purchase Contracts	490,028	539,406
Senior Unsecured Notes	983,008	1,343,706
Notes Payable – Affiliated	400,000	-
Notes Payable – Nonaffiliated	138,024	146,878
Less Portion Due Within One Year	(12,354)	(431,854)
Long-term Debt Excluding Portion Due Within One Year	$ 1,998,706	$ 1,608,086

There are certain limitations on establishing additional liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.30	2024 – April 1	$ -	$ 10,000
Unamortized Discount		-	(50)
Total		$ -	$ 9,950

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2004	2003
			(in thousands)	
Mason County, West Virginia	5.4500	2016 – December 1	$ 50,000	$ 50,000
Marshall County, West Virginia	5.4500	2014 – July 1	50,000	50,000
	5.9000	2022 – April 1	35,000	35,000
	6.8500	2022 – June 1	-	50,000
	(a)	2022 – June 1	50,000	50,000
Ohio Air Quality Development Authority	5.1500	2026 – May 1	50,000	50,000
	5.5625	2022 – October 1	19,565	19,565
	5.5625	2023 – January 1	19,565	19,565
	(b)	2028 – April 1	40,000	40,000
	(c)	2028 – April 1	40,000	40,000
	6.3750	2029 – January 1 (d)	51,000	51,000
	6.3750	2029 – April 1 (d)	51,000	51,000
	(b)	2029 – April 1	18,000	18,000
	(c)	2029 – April 1	18,000	18,000
	Unamortized Discount		(2,102)	(2,724)
	Total		$ 490,028	$ 539,406

(a) A floating interest rate is determined daily. The rate was 2.19% and 1.29% on December 31, 2004 and 2003, respectively.
(b) A floating interest rate is determined weekly. The rate was 2.10% and 1.13% on December 31, 2004 and 2003, respectively. These bonds will be redeemed in March 2005 with proceeds from an issuance in January 2005.
(c) A floating interest rate is determined weekly. The rate was 2.10% and 1.20% on December 31, 2004 and 2003, respectively. These bonds will be redeemed in March 2005 with proceeds from an issuance in January 2005.
(d) These bonds were redeemed in February 2005 with proceeds from an issuance in January 2005.

Under the terms of the installment purchase contracts, OPCo is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments range from monthly to semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.750	2004 – July 1	$ -	$ 100,000
7.000	2004 – July 1	-	75,000
6.730	2004 – November 1	-	48,000
6.240	2008 – December 4	37,225	37,225
7.375	2038 – June 30	-	140,000
5.500	2013 – February 15	250,000	250,000
4.850	2014 – January 15	225,000	225,000
6.600	2033 – February 15	250,000	250,000
6.375	2033 – July 15	225,000	225,000
Unamortized Discount		(4,217)	(6,519)
Total		$ 983,008	$ 1,343,706

Notes Payable to Parent were as follows:

% Rate	Due	2004	2003
		(in thousands)	
3.32	2006 – May 15	$ 200,000	$ -
5.25	2015 – June 1	200,000	-
Total		$ 400,000	$ -

Notes Payable to third parties outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.810	2008 – March 31	$ 19,024	$ 24,878
6.270	2009 – March 31	38,000	41,000
7.490	2009 – April 15	70,000	70,000
7.210	2009 – June 15	11,000	11,000
Total		$ 138,024	$ 146,878

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ 12,354
2006	212,354
2007	17,853
2008	55,188
2009	77,500
Later Years	1,642,130
Total Principal Amount	2,017,379
Unamortized Discount	(6,319)
Total	$ 2,011,060

OHIO POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to OPCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Ohio Power Company:

We have audited the accompanying consolidated balance sheets of Ohio Power Company Consolidated as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ohio Power Company Consolidated as of December 31, 2004 and 2003, and the results of its operations and its 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.

As discussed in Note 2 to the consolidated financial statements, the Company adopted 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 1,047,521	$ 1,102,822	$ 793,647	$ 957,000	$ 956,398
Operating Income	75,076	92,863	84,721	96,988	96,669
Interest Charges	37,957	44,784	40,422	39,249	38,980
Net Income	37,542	53,891	41,060	57,759	66,663
BALANCE SHEETS DATA					
Electric Utility Plant	$ 2,871,016	$ 2,813,681	$ 2,766,328	$ 2,695,099	$ 2,604,670
Accumulated Depreciation and Amortization	1,117,113	1,069,216	1,037,222	989,426	963,176
Net Electric Utility Plant	$ 1,753,903	$ 1,744,465	$ 1,729,106	$ 1,705,673	$ 1,641,494
Total Assets	$ 2,068,818	$ 1,977,317	$ 1,986,147	$ 1,943,928	$ 2,325,500
Common Shareholder's Equity	529,256	483,008	399,247	480,240	474,934
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,267	5,267	5,267	5,267
Trust Preferred Securities (a)	-	-	75,000	75,000	75,000
Long-term Debt (b)	546,092	574,298	545,437	451,129	470,822
Obligations Under Capital Leases (b)	1,284	1,010	-	-	-

(a) See "Trust Preferred Securities" section of Note 16.
(b) Including portion due within one year.

Public Service Company of Oklahoma (PSO) is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 509,000 retail customers in eastern and southwestern Oklahoma. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. PSO also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Power pool members are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

2004 Compared to 2003

Net Income decreased $16 million from the prior year primarily due to increased operations and maintenance expenses for power plant maintenance and transmission and distribution expenses.

Fluctuations occurring in the retail portion of fuel and purchased power expense generally do not impact operating income, as they are offset in revenues due to the functioning of the fuel clause adjustment in Oklahoma.

Operating Income

Operating Income for the year decreased $18 million primarily due to:

- A $24 million increase in Other Operation expenses. Transmission expense increased $11 million primarily related to prior years true-up for OATT transmission recorded in 2004 resulting from revised data from ERCOT for the years 2001-2003. Distribution expenses increased $7 million resulting mainly from a labor settlement and various inventory and tracking system upgrades. General and Administrative expense increased $8 million primarily due to outside services, mostly legal, and pension expense partially offset by the Medicare subsidy.

- A $10 million increase in Maintenance expenses primarily due to increased power plant maintenance and increased storm damage costs.
- A $4 million decrease in transmission revenues primarily due to a 2003 adjustment of nonaffiliated transactions.
- A $6 million increase in Taxes Other Than Income Taxes primarily due to increased property taxes of $4 million attributable to changes in property values. Also, state and local franchise taxes increased $2 million primarily due to a true-up of prior years recorded in 2003.
- A $3 million increase in Depreciation and Amortization expense primarily due to increases in depreciable plant.
- A $3 million decrease in miscellaneous revenue categories due to items such as reduced rental revenues, reduced miscellaneous service charges, and reduced wholesale base revenues as a result of the loss of one customer.

The decrease was partially offset by:

- A $28 million decrease in Income Taxes. See Income Taxes section below for further discussion.
- A $7 million increase in off-system sales margins primarily due to the end of merger related mitigation sales losses in 2003.

Fuel and Purchased Power

Fuel expense decreased 18% due to lower KWH generated of 16%, offset by slightly higher cost per KWH of 3%. In addition, Fuel expenses were affected by a decrease in deferred fuel expense of $28 million. Purchased Power expense increased 26% due to a 15% increase of KWH purchased and higher cost per KWH of 18%.

Other Impacts on Earnings

Nonoperating Income decreased $7 million compared to the prior year period in large part due to a gain on the disposition of land recorded in 2003.

Nonoperating Income Tax Expense (Credit) decreased $2 million also due to the gain mentioned above. See Income Taxes section below for further discussion.

Interest Charges decreased $7 million compared to the prior year due the retirement of higher rate First Mortgage Bonds replaced by lower rate Senior Unsecured Notes and the retirement of $77 million of Trust Preferred Securities.

Income Taxes

The effective tax rates for 2004 and 2003 were 17.2% and 41.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is due primarily to an increase in favorable federal income tax adjustments and a decrease in state income taxes.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	A-	A
Senior Unsecured Debt	Baa1	BBB	A-

In July 2004, Standard and Poor's upgraded the credit rating of our First Mortgage Bonds from BBB to A- due to a change in rating methodology. The principal amount of First Mortgage Bonds currently outstanding is $50 million.

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:

Payment 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)	$ 50.0	$ 50.0	$ 50.0	$ 396.4	$ 546.4
Advances from Affiliates (b)	55.0	-	-	-	55.0
Capital Lease Obligations (c)	0.6	0.6	0.1	0.1	1.4
Noncancelable Operating Leases (c)	5.8	9.3	4.5	6.7	26.3
Fuel Purchase Contracts (d)	251.3	159.8	56.9	82.1	550.1
Energy and Capacity Purchase Contracts (e)	49.4	99.3	90.1	208.6	447.4
Total	$ 412.1	$ 319.0	$ 201.6	$ 693.9	$ 1,626.6

(a) See Schedule of Long-term Debt. Represents principal only excluding interest.
(b) Represents short-term borrowings from the Utility Money Pool.
(c) See Note 15.
(d) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(e) Represents contractual cash flows of energy and capacity purchase contracts.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

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

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

Total MTM Risk Management Contract Net Assets at December 31, 2003	$ 14,057
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(1,007)
Fair Value of New Contracts When Entered During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(187)
Change in Fair Value Due to Valuation Methodology Changes (d)	-
Changes in Fair Value of Risk Management Contracts (e)	-
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	1,908
Total MTM Risk Management Contract Net Assets	14,771
Net Cash Flow Hedge Contracts (g)	(66)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 14,705

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.
(b) "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 that were 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 Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

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

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 15,389	$ 5,999	$ 21,388
Noncurrent Assets	14,470	7	14,477
Total MTM Derivative Contract Assets	29,859	6,006	35,865
Current Liabilities	(8,034)	(5,671)	(13,705)
Noncurrent Liabilities	(7,054)	(401)	(7,455)
Total MTM Derivative Contract Liabilities	(15,088)	(6,072)	(21,160)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 14,771	$ (66)	$ 14,705

(a) Does not include Cash Flow 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 Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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 Fair Value of Contracts as of December 31, 2004 (in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (1,949)	$ (70)	$ 980	$ -	$ -	$ -	$ (1,039)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	9,639	2,835	2,442	1,189	-	-	16,105
Prices Based on Models and Other Valuation Methods (b)	(335)	(1,764)	(1,853)	425	1,313	1,919	(295)
Total	$ 7,355	$ 1,001	$ 1,569	$ 1,614	$ 1,313	$ 1,919	$ 14,771

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in 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 are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges.

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 operations. We monitor these risks on our future operations and may employ various commodity instruments 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.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges 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. In accordance with GAAP, all amounts are presented net of related income taxes.

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

	Power	Interest Rate	Total
Beginning Balance December 31, 2003	$ 156	$ -	$ 156
Changes in Fair Value (a)	1,313	(600)	713
Reclassifications from AOCI to Net Income (b)	(469)	-	(469)
Ending Balance December 31, 2004	$ 1,000	$ (600)	$ 400

(a) "Changes in Fair Value" shows 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.
(b) "Reclassifications from AOCI to Net Income" represents 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.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,182 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

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

December 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$238	$778	$335	$115	$258	$1,004	$420	$100

VaR Associated with Debt Outstanding

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 $35 million and $66 million at December 31, 2004 and 2003, respectively. 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 negatively affect our results of operations or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,036,831	$ 1,079,692	$ 784,208
Sales to AEP Affiliates	10,690	23,130	9,439
TOTAL	1,047,521	1,102,822	793,647
OPERATING EXPENSES			
Fuel for Electric Generation	434,396	526,563	246,199
Purchased Energy for Resale	79,612	35,685	47,507
Purchased Electricity from AEP Affiliates	104,001	109,639	89,454
Other Operation	153,489	129,246	133,538
Maintenance	63,529	53,076	48,060
Depreciation and Amortization	89,711	86,455	85,896
Taxes Other Than Income Taxes	38,587	32,287	34,077
Income Taxes	9,120	37,008	24,195
TOTAL	972,445	1,009,959	708,926
OPERATING INCOME	75,076	92,863	84,721
Nonoperating Income	1,296	8,026	1,920
Nonoperating Expenses	2,184	1,385	6,971
Nonoperating Income Tax Expense (Credit)	(1,311)	829	(1,812)
Interest Charges	37,957	44,784	40,422
NET INCOME	37,542	53,891	41,060
Gain on Reacquired Preferred Stock	2	-	1
Preferred Stock Dividend Requirements	213	213	213
EARNINGS APPLICABLE TO COMMON STOCK	$ 37,331	$ 53,678	$ 40,848

The common stock of PSO is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 157,230	$ 180,016	$ 142,994	$ -	$ 480,240
Gain on Reacquired Preferred Stock			1		1
Common Stock Dividends			(67,368)		(67,368)
Preferred Stock Dividends			(213)		(213)
TOTAL					412,660
COMPREHENSIVE LOSS					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $22				(42)	(42)
Minimum Pension Liability, Net of Tax of $29,309				(54,431)	(54,431)
NET INCOME			41,060		41,060
TOTAL COMPREHENSIVE LOSS					(13,413)
DECEMBER 31, 2002	157,230	180,016	116,474	(54,473)	399,247
Capital Contribution from Parent Company		50,000			50,000
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(213)		(213)
Distribution of Investment in AEMT, Inc. Preferred Shares to Parent Company			(548)		(548)
TOTAL					418,486
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $106				198	198
Minimum Pension Liability, Net of Tax of $5,649				10,433	10,433
NET INCOME			53,891		53,891
TOTAL COMPREHENSIVE INCOME					64,522
DECEMBER 31, 2003	157,230	230,016	139,604	(43,842)	483,008
Gain on Reacquired Preferred Stock			2		2
Common Stock Dividends			(35,000)		(35,000)
Preferred Stock Dividends			(213)		(213)
TOTAL					447,797
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $131				244	244
Minimum Pension Liability, Net of Tax of $23,516				43,673	43,673
NET INCOME			37,542		37,542
TOTAL COMPREHENSIVE INCOME					81,459
DECEMBER 31, 2004	$ 157,230	$ 230,016	$ 141,935	$ 75	$ 529,256

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
December 31, 2004 and 2003

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$ 1,072,022	$ 1,065,408
Transmission	468,735	458,577
Distribution	1,089,187	1,031,229
General	200,044	203,756
Construction Work in Progress	41,028	54,711
Total	2,871,016	2,813,681
Accumulated Depreciation and Amortization	1,117,113	1,069,216
TOTAL - NET	1,753,903	1,744,465
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	4,401	4,631
Other Investments	81	2,320
TOTAL	4,482	6,951
CURRENT ASSETS		
Cash and Cash Equivalents	91	3,738
Other Cash Deposits	188	10,520
Accounts Receivable:		
Customers	34,002	28,515
Affiliated Companies	46,399	19,852
Miscellaneous	6,984	-
Allowance for Uncollectible Accounts	(76)	(37)
Fuel Inventory	14,268	18,331
Materials and Supplies	35,485	38,118
Risk Management Assets	21,388	18,586
Regulatory Asset for Under-Recovered Fuel Costs	366	24,170
Margin Deposits	2,881	4,351
Prepayments and Other	1,378	2,655
TOTAL	163,354	168,799
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	14,705	14,357
Other	17,246	14,342
Long-term Risk Management Assets	14,477	10,379
Prepaid Pension Obligations	82,419	-
Deferred Charges and Other Assets	18,232	18,024
TOTAL	147,079	57,102
TOTAL ASSETS	$ 2,068,818	$ 1,977,317

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $15 Par Value Per Share:	$ 157,230	$ 157,230
Authorized - 11,000,000 Shares		
Issued - 10,482,000 Shares		
Outstanding - 9,013,000 Shares		
Paid-in Capital	230,016	230,016
Retained Earnings	141,935	139,604
Accumulated Other Comprehensive Income (Loss)	75	(43,842)
Total Common Shareholder's Equity	529,256	483,008
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,267
Total Shareholders' Equity	534,518	488,275
Long-term Debt:		
Nonaffiliated	446,092	490,598
Affiliated	50,000	-
Total Long-term Debt	496,092	490,598
TOTAL	1,030,610	978,873
CURRENT LIABILITIES		
Long-term Debt Due Within One Year – Nonaffiliated	50,000	83,700
Advances from Affiliates	55,002	32,864
Accounts Payable:		
General	71,442	48,808
Affiliated Companies	58,632	57,206
Customer Deposits	33,757	26,547
Taxes Accrued	18,835	27,157
Interest Accrued	4,023	3,706
Risk Management Liabilities	13,705	11,067
Obligations Under Capital Leases	537	452
Other	30,477	35,234
TOTAL	336,410	326,741
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	384,090	335,434
Long-term Risk Management Liabilities	7,455	3,602
Regulatory Liabilities:		
Asset Removal Costs	220,298	214,033
Deferred Investment Tax Credits	28,620	30,411
SFAS 109 Regulatory Liability, Net	21,963	24,937
Other	19,676	15,406
Obligations Under Capital Leases	747	558
Deferred Credits and Other	18,949	47,322
TOTAL	701,798	671,703
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,068,818	$ 1,977,317

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 37,542	$ 53,891	$ 41,060
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	89,711	86,455	85,896
Deferred Income Taxes	22,034	(14,641)	75,659
Deferred Investment Tax Credits	(1,791)	(1,791)	(1,791)
Mark-to-Market of Risk Management Contracts	(714)	(10,511)	(1,111)
Fuel Recovery	23,804	52,300	(85,190)
Pension Contribution	(48,701)	(88)	-
Change in Other Noncurrent Assets	(26,325)	(9,646)	3,273
Change in Other Noncurrent Liabilities	26,113	16,862	(20,097)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(38,979)	(2,588)	(3,737)
Fuel, Materials and Supplies	6,696	899	996
Accounts Payable	24,060	(33,231)	25,629
Taxes Accrued	(8,322)	20,303	(11,296)
Customer Deposits	7,210	4,758	748
Interest Accrued	317	(3,273)	(319)
Other Current Assets	2,746	(4,271)	(366)
Other Current Liabilities	(4,670)	10,729	12,740
Net Cash Flows From Operating Activities	110,731	166,157	122,094
INVESTING ACTIVITIES			
Construction Expenditures	(82,326)	(86,815)	(89,365)
Change in Other Cash Deposits, Net	10,332	(3,289)	(4,284)
Proceeds from Sale of Assets	458	2,862	-
Other	-	-	963
Net Cash Flows Used For Investing Activities	(71,536)	(87,242)	(92,686)
FINANCING ACTIVITIES			
Capital Contributions from Parent Company	-	50,000	-
Issuance of Long-term Debt – Nonaffiliated	82,255	148,734	-
Issuance of Long-term Debt – Affiliated	50,000	-	187,850
Retirement of Long-term Debt – Nonaffiliated	(162,020)	(200,000)	(106,000)
Retirement of Cumulative Preferred Stock	(2)	-	-
Change in Advances to/from Affiliates, Net	22,138	(53,241)	(36,982)
Dividends Paid on Common Stock	(35,000)	(30,000)	(67,368)
Dividends Paid on Cumulative Preferred Stock	(213)	(213)	(213)
Net Cash Flows Used For Financing Activities	(42,842)	(84,720)	(22,713)
Net Increase (Decrease) in Cash and Cash Equivalents	(3,647)	(5,805)	6,695
Cash and Cash Equivalents at Beginning of Period	3,738	9,543	2,848
Cash and Cash Equivalents at End of Period	$ 91	$ 3,738	$ 9,543

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $32,961,000, $44,703,000 and $38,620,000 and for income taxes was $2,387,000, $36,470,000 and $(38,943,000) in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $796,000. There was a noncash distribution of $548,000 in preferred shares in AEMT, Inc. to PSO's Parent Company in 2003.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
SCHEDULE OF PREFERRED STOCK
December 31, 2004 and 2003

PREFERRED STOCK:
Cumulative $100 par value per share – authorized shares 700,000, redeemable at our option upon 30 days notice.

Series	Call Price December 31, 2004	Number of Shares Redeemed Year Ended December 31,			Shares Outstanding December 31, 2004	2004	2003
		2004	2003	2002		(in thousands)	
Not Subject to Mandatory Redemption:							
4.00%	$105.75	50	2	6	44,548	$ 4,455	$ 4,460
4.24%	103.19	-	-	1	8,069	807	807
Total						$ 5,262	$ 5,267

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
SCHEDULE OF LONG-TERM DEBT
December 31, 2004 and 2003
(in thousands)

	2004	2003
	(in thousands)	
LONG-TERM DEBT:		
First Mortgage Bonds	$ 49,970	$ 99,864
Installment Purchase Contracts	46,360	47,358
Senior Unsecured Notes	399,762	349,756
Notes Payable to Trust (a)	-	77,320
Notes Payable – Affiliated	50,000	-
Less Portion Due Within One Year	(50,000)	(83,700)
Long-term Debt Excluding Portion Due Within One Year	$ 496,092	$ 490,598

(a) See "Trust Preferred Securities" section of Note 16 for discussion of Notes Payable to Trust.

There are certain limitations on establishing additional liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of our affiliates.

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.375	2004 – December 1	$ -	$ 50,000
6.500	2005 – June 1	50,000	50,000
Unamortized Discount		(30)	(136)
Total		$ 49,970	$ 99,864

First Mortgage Bonds are secured by a first mortgage lien on Electric Utility Plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2004	2003
			(in thousands)	
Oklahoma Environmental Finance Authority (OEFA)	5.900	2007 – December 1	$ -	$ 1,000
Oklahoma Development Finance Authority (ODFA)	4.875	2014 – June 1	-	33,700
	Variable	2014 – June 1 (a)	33,700	-
Red River Authority of Texas	6.000	2020 – June 1	12,660	12,660
	Unamortized Discount		-	(2)
	Total		$ 46,360	$ 47,358

(a) The interest rate on December 31, 2004 was 1.750%.

Under the terms of the installment purchase contracts, PSO is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
4.700	2009 – June 15	$ 50,000	$ -
4.850	2010 – September 15	150,000	150,000
6.000	2032 – December 31	200,000	200,000
Unamortized Discount		(238)	(244)
Total		$ 399,762	$ 349,756

Notes Payable to Trust was outstanding as follows:

% Rate	Due	2004	2003
		(in thousands)	
8.000	2037 – April 30	$ -	$ 77,320

See "Trust Preferred Securities" section of Note 16 for discussion of Notes Payable to Trust.

Notes Payable to parent company was as follows:

% Rate	Due	2004	2003
		(in thousands)	
3.350	2006 – May 15	$ 50,000	$ -

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ 50,000
2006	50,000
2007	-
2008	-
2009	50,000
Later Years	396,360
Total Principal Amount	546,360
Unamortized Discount	(268)
Total	$ 546,092

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to PSO's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Public Service Company of Oklahoma:

We have audited the accompanying balance sheets of Public Service Company of Oklahoma as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma as of December 31, 2004 and 2003, and the results of its operations and its 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.

As discussed in Note 2 to the financial statements, the Company adopted 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 1,087,346	$ 1,146,842	$ 1,084,720	$ 1,101,326	$ 1,118,274
Operating Income	143,178	150,136	142,469	146,207	128,278
Interest Charges	53,529	63,779	59,168	57,581	59,457
Income Before Cumulative Effect of Accounting Changes	89,457	89,624	82,992	89,367	72,672
Cumulative Effect of Accounting Changes, Net of Tax	-	8,517	-	-	-
Net Income	89,457	98,141	82,992	89,367	72,672
BALANCE SHEETS DATA					
Electric Utility Plant	$ 3,887,367	$ 3,799,460	$ 3,596,174	$ 3,460,764	$ 3,319,024
Accumulated Depreciation and Amortization	1,709,758	1,617,846	1,477,875	1,342,003	1,259,509
Net Electric Utility Plant	$ 2,177,609	$ 2,181,614	$ 2,118,299	$ 2,118,761	$ 2,059,515
Total Assets	$ 2,646,309	$ 2,581,963	$ 2,428,138	$ 2,509,291	$ 2,855,885
Common Shareholder's Equity	768,618	696,660	661,769	689,578	674,652
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700	4,701	4,701	4,701
Trust Preferred Securities (a)	-	-	110,000	110,000	110,000
Long-term Debt (b)	805,369	884,308	693,448	645,283	645,963
Obligations Under Capital Leases (b)	34,546	21,542	-	-	-

(a) See "Trust Preferred Securities" section of Note 16.
(b) Including portion due within one year.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Southwestern Electric Power Company (SWEPCo) is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 444,000 retail customers in our service territory in northeastern Texas, northwestern Louisiana and western Arkansas. We consolidate Southwest Arkansas Utilities Corporation and Dolet Hills Lignite Company, LLC, our wholly-owned subsidiaries. We also consolidate Sabine Mining Company, a variable interest entity. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. We also sell electric power at wholesale to other utilities, municipalities and electric cooperatives.

Power pool members are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

Net Income decreased $9 million for 2004. The decrease is primarily due to the $9 million (net of tax) Cumulative Effect of Accounting Changes recorded in 2003.

Net Income increased $15 million for 2003 primarily due to an $8 million increase in Operating Income and the adoption of SFAS 143, which resulted in Cumulative Effect of Accounting Changes of $9 million in the first quarter of 2003. Significant fluctuations occurred in revenues, fuel and purchased power due to certain Interchange Cost Reconstruction (ICR) adjustments in 2002; however, income is generally not affected due to the functioning of fuel adjustment clauses in the retail jurisdictions.

Fluctuations occurring in the retail portion of fuel and purchased power expense, except for capacity related items, generally do not impact operating income, as they are offset in revenues and/or operations expense due to the functioning of the fuel adjustment clauses in the states in which we serve.

2004 Compared to 2003

Operating Income

Operating Income decreased by $7 million primarily due to:

- A $14 million increase in Other Operation expenses primarily related to a prior year true-up for OATT transmission recorded in 2004 resulting from revised data from ERCOT for the years 2001-2003 offset in part by the sale of emission allowances.
- A $10 million increase in Taxes Other Than Income Taxes primarily due to higher franchise taxes of $8 million resulting from a true-up of prior years recorded in 2003 and higher property related taxes.
- An $8 million increase in Depreciation and Amortization expenses primarily due to the amortization of a regulatory asset for the recovery of fuel related costs in Arkansas established in 2003 by a credit to amortization and adjustments to excess earnings accruals per the Texas Restructuring Legislation (see "Texas Restructuring" and "Unrefunded Excess Earnings" in Note 6). Also, depreciation increased due to increases in depreciable plant.
- A $5 million decrease in margins from risk management activities.
- A $4 million increase in Maintenance expenses primarily due to scheduled power plant maintenance, as well as increased overhead line maintenance.
- A $4 million decrease in the portion of margin the company retains from off-system sales primarily due to decreased realization on off-system sales.
- A $2 million decrease in retail base revenues due to a decline of 5% in heating and cooling degree-days.

The decrease in Operating Income was partially offset by:

- An $18 million decrease in Income Taxes. See Income Taxes section below for further discussion.
- A $2 million decrease in provision for rate refund primarily due to a wholesale fuel refund in 2003.

Fuel and Purchased Power

Fuel expense decreased 12% primarily due to lower KWH generation of 2% and lower cost per KWH of 8%. Purchased power expense decreased 22% in large part due to decreased capacity purchases reflecting a $9 million refund received for prior year purchased capacity amounts. Capacity related transactions are not included in the fuel adjustment clauses, and therefore, changes impact operating income.

Other Impacts on Earnings

Interest Charges decreased $10 million as a result of refinancing higher interest rate debt with lower interest rate debt.

The increase in Minority Interest expense of $2 million is a result of consolidating Sabine Mining Company (Sabine), effective July 1, 2003, due to implementation of FIN 46. We now record the depreciation, interest and other operating expenses of Sabine and eliminate Sabine's revenues against our fuel expenses. While there was no effect to net income as a result of consolidation, some individual income statement lines were affected.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to a one-time after tax impact of adopting SFAS 143 and EITF 02-3 in 2003 (see Note 2).

Income Taxes

The effective tax rates for 2004 and 2003 were 28% and 36.3%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to federal income tax adjustments, a decrease in state income taxes and permanent differences relating primarily to a Medicare subsidy credit.

2003 Compared to 2002

Operating Income

Operating Income increased by $8 million primarily due to:

- A $12 million increase in retail base revenues due to increased customers and their average usage, offset in part by milder weather. Heating cooling degree-days declined 6%.
- A $12 million increase in wholesale margins due to an increase in our allocation of overall AEP off-system sales percentages resulting from increased amounts of off-system sales.
- An $11 million decrease in Other Operation expenses primarily due to decreases in customer services, outside services and other administrative expenses.
- A $7 million increase in income from risk management activities.

The increase in Operating Income was partially offset by:

- A $21 million increase in Income Taxes. See Income Taxes section below for further discussion.
- A $9 million decrease in wholesale base margins primarily due to decreased demand from wholesale customers.
- A $4 million decrease in capacity revenues due to the elimination of the requirement under the Texas Restructuring Legislation to sell capacity (see Note 6).

Other Impacts on Earnings

Nonoperating Income Tax Expense (Credit) increased by $5 million due to changes in certain book/tax timing differences accounted for on a flow-through basis, changes in consolidated tax savings and tax return and tax accrual adjustments.

Interest Charges increased $5 million primarily due to higher levels of outstanding debt, consolidation of Sabine and increased financing activity at Dolet Hills.

The increase in Minority Interest expense of $2 million is a result of consolidating Sabine effective July 1, 2003, due to implementation of FIN 46. We now record the depreciation, interest and other operating expenses of Sabine and eliminate Sabine's revenues against our fuel expenses. While there was no effect to net income as a result of consolidation, some individual income statement lines were affected.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 in 2003 (see Note 2).

Income Taxes

The effective tax rates for 2003 and 2002 were 36.3% and 29.9%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is primarily due to an increase in state income taxes and permanent differences relating primarily to book depletion.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	A-	A
Senior Unsecured Debt	Baa1	BBB	A-

In July 2004, Standard and Poor's upgraded the credit rating of the First Mortgage Bonds from BBB to A- due to a change in rating methodology. The principal amount of First Mortgage Bonds currently outstanding is $96 million.

Cash Flow

Cash flows for the years ended December 31, 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(in thousands)	
Cash and cash equivalents at beginning of period	$ 5,676	$ -	$ 5,023
Cash flows from (used for):			
Operating activities	209,734	248,094	210,563
Investing activities	(97,933)	(114,828)	(112,318)
Financing activities	(115,169)	(127,590)	(103,268)
Net increase (decrease) in cash and cash equivalents	(3,368)	5,676	(5,023)
Cash and cash equivalents at end of period	$ 2,308	$ 5,676	$ -

Operating Activities

Our net cash flows from operating activities were $210 million in 2004. We produced income of $89 million during the period and noncash expense items of $129 million for Depreciation and Amortization. Change in Pension Contribution of $46 million is due to the pension plan funding. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are Accounts Receivable, Net, Fuel, Materials and Supplies and Taxes Accrued. Accounts Receivable, Net increased related to increased affiliated energy purchases. The decrease in Fuel, Materials and Supplies is primarily due to lower purchases of fuel. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP 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.

Our net cash flows from operating activities were $248 million in 2003. We produced income of $98 million during the period and noncash expense items of $121 million for Depreciation and Amortization and $9 million for Cumulative Effect of Accounting Changes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant were Accounts Receivable, Net and Accounts Payable. Accounts Receivable, Net decreased primarily due to prior year adjustments to the interchange cost reconstruction system and lower affiliated energy purchases. The decrease in Accounts Payable was related to lower fuel purchases.

Our net cash flows from operating activities were $211 million in 2002. We produced income of $83 million during the period and noncash expense items of $123 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant were Accounts Receivable, Net, Fuel, Materials and Supplies and Taxes Accrued. Accounts Receivable, Net decreased primarily due to an adjustment to the interchange cost reconstruction system. Fuel, Materials and Supplies increased due to higher coal purchases. Taxes accrued increased due to higher income taxes offset in part by state and local franchise taxes.

Investing Activities

Cash flows used for investing activities during 2004, 2003 and 2002 were $98 million, $115 million and $112 million, respectively. They were comprised primarily of Construction Expenditures related to projects for improved transmission and distribution service reliability.

Financing Activities

Cash flows used for financing activities were $115 million during 2004. During the first and second quarter, we retired $80 million and $40 million of First Mortgage Bonds, respectively. Three Installment Purchase Contracts were retired for Titus County with fixed interest rates in the second quarter totaling $41 million which were replaced by one Installment Purchase Contract with a variable interest rate for $41 million. During the third quarter of 2004, we issued a Note Payable to AEP for $50 million. Common Stock Dividends were $60 million.

Cash flows used for financing activities were $128 million during 2003. During the first quarter of 2003, we retired $55 million of First Mortgage Bonds at maturity. In April 2003, we issued $100 million of Senior Unsecured Notes due 2015 at a coupon of 5.375%. In May 2003, one of our mining subsidiaries issued $44 million of notes due in 2011 at a coupon of 4.47%. The loan was used primarily to reduce a note to us with an interest rate of 8.06%. During the fourth quarter of 2003, we had an early redemption of $45 million of First Mortgage Bonds due in 2023. Common Stock dividends were $73 million.

Cash flows used for financing activities were $103 million for 2002. During the first quarter of 2002, we retired Senior Unsecured Notes of $150 million. We issued $200 million of Senior Unsecured Notes in the second quarter of 2002. Common stock dividends were $57 million.

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:

Payment 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)	$ 210.0	$ 118.1	$ 11.0	$ 465.6	$ 804.7
Capital Lease Obligations (b)	6.2	11.9	11.3	20.5	49.9
Noncancelable Operating Leases (b)	6.8	14.8	17.1	10.6	49.3
Fuel Purchase Contracts (c)	198.4	355.7	232.8	472.3	1,259.2
Energy and Capacity Purchase Contracts (d)	27.9	56.1	50.9	117.9	252.8
Total	$ 449.3	$ 556.6	$ 323.1	$ 1,086.9	$ 2,415.9

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.
(b) See Note 15.
(c) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(d) Represents contractual cash flows of energy and capacity purchase contracts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2004 under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millons)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Standby Letters of Credit (a)	$ 4.0	$ -	$ -	$ -	$ 4.0
Guarantees of the Performance of Outside Parties (b)	10.5	-	22.0	105.0	137.5
Total	$ 14.5	$ -	$ 22.0	$ 105.0	$ 141.5

(a) We have issued standby letters of credit to third parties. These letters of credit cover 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 $4.0 million maturing in December 2005. There is no recourse to third parties in the event these letters of credit are drawn.
(b) See Note 8.

Other

On July 1, 2003, we consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, we recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, we currently record all expenses (depreciation, interest and other operation expense) of Sabine and eliminate Sabine's revenues against our fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

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

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

Total MTM Risk Management Contract Net Assets at December 31, 2003	$ 16,606
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(4,481)
Fair Value of New Contracts When Entered During the Period (b)	743
Net Option Premiums Paid/(Received) (c)	(221)
Change in Fair Value Due to Valuation Methodology Changes (d)	62
Changes in Fair Value of Risk Management Contracts (e)	3,008
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	1,810
Total MTM Risk Management Contract Net Assets	17,527
Net Cash Flow Hedge Contracts (g)	(2,704)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 14,823

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.
(b) "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 that were 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 Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

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

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 18,260	$ 7,119	$ 25,379
Noncurrent Assets	17,170	9	17,179
Total MTM Derivative Contract Assets	35,430	7,128	42,558
Current Liabilities	(9,533)	(9,074)	(18,607)
Noncurrent Liabilities	(8,370)	(758)	(9,128)
Total MTM Derivative Contract Liabilities	(17,903)	(9,832)	(27,735)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 17,527	$ (2,704)	$ 14,823

(a) Does not include Cash Flow 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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 Fair Value of Contracts as of December 31, 2004 (in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (2,313)	$ (84)	$ 1,163	$ -	$ -	$ -	$ (1,234)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	11,438	3,364	2,898	1,411	-	-	19,111
Prices Based on Models and Other Valuation Methods (b)	(398)	(2,092)	(2,199)	504	1,558	2,277	(350)
Total	$ 8,727	$ 1,188	$ 1,862	$ 1,915	$ 1,558	$ 2,277	$ 17,527

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in 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 are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges.

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 operations. We monitor these risks on our future operations and may employ various commodity instruments 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.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges 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. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Years Ended December 31, 2004
(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2003	$ 184	$ -	$ 184
Changes in Fair Value (a)	1,558	(2,008)	(450)
Reclassifications from AOCI to Net Income (b)	(554)	-	(554)
Ending Balance December 31, 2004	$ 1,188	$ (2,008)	$ (820)

(a) "Changes in Fair Value" shows 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.

(b) "Reclassifications from AOCI to Net Income" represents 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.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,413 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

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

December 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$283	$923	$398	$136	$304	$1,182	$495	$118

VaR Associated with Debt Outstanding

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 $31 million and $57 million at December 31, 2004 and 2003, respectively. 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 negatively affect our results of operations or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,016,156	$ 1,077,988	$ 1,012,391
Sales to AEP Affiliates	71,190	68,854	72,329
TOTAL	1,087,346	1,146,842	1,084,720
OPERATING EXPENSES			
Fuel for Electric Generation	387,554	440,080	391,355
Purchased Energy for Resale	35,521	34,850	44,119
Purchased Electricity from AEP Affiliates	29,054	47,914	42,022
Other Operation	188,601	174,714	186,003
Maintenance	74,091	70,443	66,855
Depreciation and Amortization	129,329	121,072	122,969
Taxes Other Than Income Taxes	63,560	53,165	55,232
Income Taxes	36,458	54,468	33,696
TOTAL	944,168	996,706	942,251
OPERATING INCOME	143,178	150,136	142,469
Nonoperating Income	4,337	3,978	3,260
Nonoperating Expenses	3,030	2,607	1,797
Nonoperating Income Tax Expense (Credit)	(1,731)	(3,396)	1,772
Interest Charges	53,529	63,779	59,168
Minority Interest	(3,230)	(1,500)	-
Income Before Cumulative Effect of Accounting Changes	89,457	89,624	82,992
Cumulative Effect of Accounting Changes, Net of Tax	-	8,517	-
NET INCOME	89,457	98,141	82,992
Preferred Stock Dividend Requirements	229	229	229
EARNINGS APPLICABLE TO COMMON STOCK	$ 89,228	$ 97,912	$ 82,763

The common stock of SWEPCo is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 135,660	$ 245,003	$ 308,915	$ -	$ 689,578
Common Stock Dividends			(56,889)		(56,889)
Preferred Stock Dividends			(229)		(229)
TOTAL					632,460
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $26				(48)	(48)
Minimum Pension Liability, Net of Tax of $28,880				(53,635)	(53,635)
NET INCOME			82,992		82,992
TOTAL COMPREHENSIVE INCOME					29,309
DECEMBER 31, 2002	135,660	245,003	334,789	(53,683)	661,769
Common Stock Dividends			(72,794)		(72,794)
Preferred Stock Dividends			(229)		(229)
TOTAL					588,746
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $125				232	232
Minimum Pension Liability, Net of Tax of $5,138				9,541	9,541
NET INCOME			98,141		98,141
TOTAL COMPREHENSIVE INCOME					107,914
DECEMBER 31, 2003	135,660	245,003	359,907	(43,910)	696,660
Common Stock Dividends			(60,000)		(60,000)
Preferred Stock Dividends			(229)		(229)
TOTAL					636,431
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $541				(1,004)	(1,004)
Minimum Pension Liability, Net of Tax of $23,550				43,734	43,734
NET INCOME			89,457		89,457
TOTAL COMPREHENSIVE INCOME					132,187
DECEMBER 31, 2004	$ 135,660	$ 245,003	$ 389,135	$ (1,180)	$ 768,618

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 1,663,161	$ 1,622,498
Transmission	632,964	615,158
Distribution	1,114,480	1,078,368
General	427,910	423,427
Construction Work in Progress	48,852	60,009
Total	3,887,367	3,799,460
Accumulated Depreciation and Amortization	1,709,758	1,617,846
TOTAL - NET	2,177,609	2,181,614
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	4,049	3,808
Other Investments	4,628	4,710
TOTAL	8,677	8,518
CURRENT ASSETS		
Cash and Cash Equivalents	2,308	5,676
Other Cash Deposits	6,292	6,048
Advances to Affiliates	39,106	66,476
Accounts Receivable:		
Customers	39,042	41,474
Affiliated Companies	28,817	10,394
Miscellaneous	5,856	4,682
Allowance for Uncollectible Accounts	(45)	(2,093)
Fuel Inventory	45,793	63,881
Materials and Supplies	36,051	33,772
Risk Management Assets	25,379	19,715
Regulatory Asset for Under-Recovered Fuel Costs	4,687	11,394
Margin Deposits	3,419	5,123
Prepayments and Other	18,331	19,078
TOTAL	255,036	285,620
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	18,000	3,235
Unamortized Loss on Reacquired Debt	20,765	19,331
Other	16,350	15,859
Long-term Risk Management Assets	17,179	12,178
Prepaid Pension Obligations	81,132	-
Deferred Charges	51,561	55,608
TOTAL	204,987	106,211
TOTAL ASSETS	$ 2,646,309	$ 2,581,963

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2004 and 2003

	2004	2003
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - $18 Par Value per share		
Authorized - 7,600,000 Shares		
Outstanding - 7,536,640 Shares	$ 135,660	$ 135,660
Paid-in Capital	245,003	245,003
Retained Earnings	389,135	359,907
Accumulated Other Comprehensive Loss	(1,180)	(43,910)
Total Common Shareholder's Equity	768,618	696,660
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700
Total Shareholders' Equity	773,318	701,360
Long-term Debt:		
Nonaffiliated	545,395	741,594
Affiliated	50,000	-
Total Long-term Debt	595,395	741,594
TOTAL	1,368,713	1,442,954
Minority Interest	1,125	1,367
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	209,974	142,714
Accounts Payable:		
General	40,001	37,646
Affiliated Companies	33,285	35,138
Customer Deposits	30,550	24,260
Taxes Accrued	45,474	28,691
Interest Accrued	12,509	16,852
Risk Management Liabilities	18,607	11,361
Obligations Under Capital Leases	3,692	3,159
Regulatory Liability for Over-Recovered Fuel	9,891	4,178
Other	33,417	53,753
TOTAL	437,400	357,752
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	399,756	349,064
Long-term Risk Management Liabilities	9,128	4,667
Reclamation Reserve	7,624	16,512
Regulatory Liabilities:		
Asset Removal Costs	249,892	236,409
Deferred Investment Tax Credits	35,539	39,864
Excess Earnings	3,167	2,600
Other	21,320	18,779
Asset Retirement Obligations	27,361	8,429
Obligations Under Capital Leases	30,854	18,383
Deferred Credits and Other	54,430	85,183
TOTAL	839,071	779,890
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,646,309	$ 2,581,963

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 89,457	$ 98,141	$ 82,992
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	129,329	121,072	122,969
Deferred Income Taxes	12,782	9,942	(3,134)
Deferred Investment Tax Credits	(4,326)	(4,326)	(4,524)
Cumulative Effect of Accounting Changes	-	(8,517)	-
Mark-to-Market of Risk Management Contracts	(921)	(12,403)	(1,151)
Fuel Recovery	12,420	(21,577)	17,713
Pension Contribution	(45,688)	(805)	-
Change in Other Noncurrent Assets	(21,251)	22,507	23,570
Change in Other Noncurrent Liabilities	37,014	47,834	(762)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(19,213)	27,527	(24,371)
Fuel, Materials and Supplies	15,809	4,168	(10,541)
Accounts Payable	502	(51,687)	11,633
Taxes Accrued	16,783	8,446	(17,441)
Customer Deposits	6,290	4,150	230
Interest Accrued	(4,343)	(761)	4,024
Other Current Assets	2,452	(6,242)	865
Other Current Liabilities	(17,362)	10,625	8,491
Net Cash Flows From Operating Activities	209,734	248,094	210,563
INVESTING ACTIVITIES			
Construction Expenditures	(103,124)	(121,124)	(111,775)
Change in Other Cash Deposits, Net	(244)	(3,979)	(1,677)
Proceeds from Sale of Assets	5,435	3,800	-
Other	-	6,475	1,134
Net Cash Flows Used For Investing Activities	(97,933)	(114,828)	(112,318)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	91,999	254,630	198,573
Issuance of Long-term Debt – Affiliated	50,000	-	-
Retirement of Long-term Debt	(224,309)	(219,482)	(150,595)
Change in Advances to/from Affiliates, Net	27,370	(89,715)	(94,128)
Dividends Paid on Common Stock	(60,000)	(72,794)	(56,889)
Dividends Paid on Cumulative Preferred Stock	(229)	(229)	(229)
Net Cash Flows Used For Financing Activities	(115,169)	(127,590)	(103,268)
Net Increase (Decrease) in Cash and Cash Equivalents	(3,368)	5,676	(5,023)
Cash and Cash Equivalents at Beginning of Period	5,676	-	5,023
Cash and Cash Equivalents at End of Period	$ 2,308	$ 5,676	$ -

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $49,739,000, $57,775,000 and $49,008,000 and for income taxes was $11,326,000, $33,616,000 and $60,451,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $16,549,000. Noncash activity in 2003 included an increase in assets and liabilities of $78 million resulting from the consolidation of Sabine Mining Company (see "Consolidation of Variable Interest Entities" section of Note 2).

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SCHEDULE OF PREFERRED STOCK
December 31, 2004 and 2003

PREFERRED STOCK:
$100 Par Value per share - Authorized 1,860,000 shares

Series	Call Price December 31, 2004	Number of Shares Redeemed Year Ended December 31, 2004	2003	2002	Shares Outstanding December 31, 2004		2004 (in thousands)		2003 (in thousands)
Not Subject to Mandatory Redemption - $100 Par:									
4.28%	$103.90	-	-	-	7,386	$	740	$	740
4.65%	102.75	-	-	-	1,907		190		190
5.00%	109.00	-	12	-	37,703		3,770		3,770
Total						$	4,700	$	4,700

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
December 31, 2004 and 2003

	2004	2003
	(in thousands)	
LONG-TERM DEBT:		
First Mortgage Bonds	$ 96,024	$ 215,712
Installment Purchase Contracts	177,879	178,531
Senior Unsecured Notes	299,686	299,216
Notes Payable to Trust (a)	113,019	113,009
Notes Payable – Nonaffiliated	68,761	77,840
Notes Payable – Affiliated	50,000	-
Less Portion Due Within One Year	(209,974)	(142,714)
Long-term Debt Excluding Portion Due Within One Year	$ 595,395	$ 741,594

(a) See "Trust Preferred Securities" section of Note 16 for discussion of Notes Payable to Trust.

There are certain limitations on establishing additional liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.750	2004 – June 1	$ -	$ 40,000
6.200	2006 – November 1	5,215	5,360
6.200	2006 – November 1	1,000	1,000
7.000	2007 – September 1	90,000	90,000
6.875	2025 – October 1	-	80,000
Unamortized Discount		(191)	(648)
Total		$ 96,024	$ 215,712

First Mortgage Bonds are secured by a first mortgage lien on Electric Utility Plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2004	2003
			(in thousands)	
Desoto County	7.600	2019 – January 1	$ -	$ 53,500
	Variable (a)	2019 – January 1	53,500	-
Sabine River Authority of Texas	6.100	2018 – April 1	81,700	81,700
Titus County	Variable (b)	2011 – July 1	41,135	-
	6.900	2004 – November 1	-	12,290
	6.000	2008 – January 1	-	12,170
	8.200	2011 – August 1	-	17,125
	Unamortized Discount		1,544	1,746
	Total		$ 177,879	$ 178,531

(a) The rate on December 31, 2004 was 1.700%.
(b) The rate on December 31, 2004 was 1.850%.

Under the terms of the installment purchase contracts, SWEPCo is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
4.500	2005 – July 1	$ 200,000	$ 200,000
5.375	2015 – April 15	100,000	100,000
Unamortized Discount		(314)	(784)
Total		$ 299,686	$ 299,216

Notes Payable to Trust was outstanding as follows:

% Rate	Due	2004	2003
		(in thousands)	
5.250 (a)	2043 – October 1	$ 113,403	$ 113,403
Unamortized Discount		(384)	(394)
Total		$ 113,019	$ 113,009

(a) The 5.25% interest rate is fixed through September 10, 2008 after which they will become floating rate bonds if the notes are not remarketed.

See "Trust Preferred Securities" section of Note 16 for discussion of Notes Payable to Trust.

Notes Payable outstanding were as follows:

	% Rate	Due	2004	2003
			(in thousands)	
Sabine Mining Company (a)	6.360	2007 – February 22	$ 4,000	$ 4,000
	Variable (b)	2008 – June 30	11,250	13,500
	7.030	2012 – February 22	20,000	20,000
Dolet Hills Lignite Company	4.470	2011 – May 16	33,511	40,340
	Total		$ 68,761	$ 77,840

(a) Sabine Mining Company was consolidated during the third quarter of 2003 due to the implementation of FIN 46.
(b) A floating interest rate is determined quarterly. The rate on December 31, 2004 was 2.325%.

Notes Payable to parent company was as follows:

% Rate	Due	2004	2003
		(in thousands)	
4.450	2010 – March 15	$ 50,000	$ -

At December 31, 2004 future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ 209,974
2006	15,754
2007	102,312
2008	5,906
2009	5,156
Later Years	465,612
Total Principal Amount	804,714
Unamortized Discount	655
Total	$ 805,369

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to SWEPCo's consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to SWEPCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company Consolidated as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company Consolidated as of December 31, 2004 and 2003, and the results of its operations and its 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.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005

NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by AEP's ten 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.

With the exception of AEGCo, Registrant Subsidiaries engage in wholesale electricity marketing and risk management activities in the United States. In addition, I&M provides barging services to both affiliated and nonaffiliated companies.

See Note 10 for additional information regarding asset impairments and assets and liabilities held for sale related to our Texas generation plants.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

AEP and its subsidiaries 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

The consolidated financial statements for APCo, CSPCo, I&M, OPCo, SWEPCo and TCC include the registrant and its wholly-owned subsidiaries and/or substantially controlled variable interest entities. 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 Nonoperating Income. OPCo and SWEPCo 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). CSPCo, PSO, SWEPCo, TCC and TNC also have generating units that are jointly-owned with nonaffiliated companies. The proportionate share of the operating costs associated with such facilities is included in the financial statements and the investments are reflected in the balance sheets.

Accounting for the Effects of Cost-Based Regulation

As cost-based rate-regulated electric public utility companies, the Registrant Subsidiaries' 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. The following Registrant Subsidiaries discontinued the application of SFAS 71 for the generation portion of their 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 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.

The Registrant Subsidiaries implemented SFAS 143 effective January 1, 2003 (see "Accounting for Asset Retirement Obligations" 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. The following table provides the annual composite depreciation rates by functional class generally used by the Registrant Subsidiaries for the year 2004:

	Nuclear	Steam	Hydro	Transmission	Distribution	General
			(in percentages)			
AEGCo	-	3.5	-	-	-	16.4
APCo	-	3.1	2.6	2.2	3.3	9.4
CSPCo	-	2.9	-	2.3	3.6	10.3
I&M	3.1	4.5	3.3	1.9	4.1	11.2
KPCo	-	3.8	-	1.7	3.5	9.2
OPCo	-	2.8	2.7	2.3	4.0	10.1
PSO	-	2.7	-	2.3	3.3	7.9
SWEPCo	-	3.3	-	2.8	3.6	6.9
TCC	-	-	-	2.3	3.4	6.5
TNC	-	2.6	-	3.0	3.2	8.4

The annual composite depreciation rates by functional class generally used by the Registrant Subsidiaries for the year 2003 were as follows:

	Nuclear	Steam	Hydro	Transmission	Distribution	General
			(in percentages)			
AEGCo	-	3.5	-	-	-	16.7
APCo	-	3.3	2.7	2.2	3.3	9.3
CSPCo	-	3.0	-	2.3	3.6	9.9
I&M	3.4	4.6	3.4	1.9	4.2	11.8
KPCo	-	3.8	-	1.7	3.5	7.1
OPCo	-	2.8	2.7	2.3	4.0	10.5
PSO	-	2.7	-	2.3	3.4	9.7
SWEPCo	-	3.3	-	2.8	3.6	8.0
TCC	2.5	2.3	1.9	2.3	3.5	8.1
TNC	-	2.6	-	3.1	3.3	10.2

The annual composite depreciation rates by functional class generally used by the Registrant Subsidiaries for the year 2002 were as follows:

	Nuclear	Steam	Hydro	Transmission	Distribution	General
			(in percentages)			
AEGCo	-	3.5	-	-	-	2.8
APCo	-	3.4	2.9	2.2	3.3	3.1
CSPCo	-	3.2	-	2.3	3.6	3.2
I&M	3.4	4.5	3.4	1.9	4.2	3.8
KPCo	-	3.8	-	1.7	3.5	2.5
OPCo	-	3.4	2.7	2.3	4.0	2.7
PSO	-	2.7	-	2.3	3.4	6.3
SWEPCo	-	3.4	-	2.7	3.6	4.7
TCC	2.5	2.6	1.9	2.3	3.5	4.0
TNC	-	2.8	-	3.1	3.3	6.8

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 related to SWEPCo were $0.65 per ton in 2004 and $0.41 in 2003 and 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.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for 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 cost is expensed as incurred (see "Accounting for Asset Retirement Obligations" section of this note).

Accounting for Asset Retirement Obligations

The following is a reconciliation of 2003 and 2004 aggregate carrying amounts of asset retirement obligations by Registrant Subsidiary:

	Balance at January 1, 2003	Accretion	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	Balance at December 31, 2003
			(in millions)			
AEGCo (a)	$ 1.1	$ -	$ -	$ -	$ -	$ 1.1
APCo (a)	20.1	1.6	-	-	-	21.7
CSPCo (a)	8.1	0.6	-	-	-	8.7
I&M (b)	516.1	37.1	-	-	-	553.2
OPCo (a)	39.5	3.2	-	-	-	42.7
SWEPCo (c)	-	0.3	8.1	-	-	8.4
TCC (d)	203.2	15.6	-	-	-	218.8

	Balance at January 1, 2004	Accretion	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	Balance at December 31, 2004
			(in millions)			
AEGCo (a)	$ 1.1	$ 0.1	$ -	$ -	$ -	$ 1.2
APCo (a)	21.7	1.7	-	(0.4)	1.6	24.6
CSPCo (a)	8.7	0.7	-	-	2.2	11.6
I&M (b)	553.2	39.8	-	-	118.8	711.8
OPCo (a)	42.7	3.4	-	-	(0.5)	45.6
SWEPCo (c)	8.4	1.3	17.7	-	-	27.4
TCC (d)	218.8	16.7	-	-	13.4	248.9

(a) Consists of asset retirement obligations related to ash ponds.
(b) Consists of asset retirement obligations related to ash ponds ($1.2 million and $1.1 million at December 31, 2004 and 2003, respectively) and nuclear decommissioning costs for the Cook Plant ($710.6 million and $552.1 million at December 31, 2004 and 2003, respectively).
(c) Consists of asset retirement obligations related to Sabine Mining in 2004 and 2003, which is now being consolidated under FIN 46 (see FIN 46 "Consolidation of Variable Interest Entities" section of Note 2), and Dolet Hills in 2004.
(d) Consists of asset retirement obligations related to nuclear decommissioning costs for STP included in Liabilities Held for Sale – Texas Generation Plants on TCC's Consolidated Balance Sheets.

Accretion expense is included in Other Operation expense in the respective income statements of the individual subsidiary registrants.

As of December 31 2004, and 2003, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $934 million ($791 million for I&M and $143 million for TCC) and $845 million ($720 million for I&M and $125 million for TCC), respectively, included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&M's Consolidated Balance Sheets and in Assets Held for Sale - Texas Generation Plants on TCC's 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 for 2004, 2003 and 2002 are as follows:

	2004	2003	2002
		(in millions)	
AEGCo	$ -	$ -	$ 0.4
APCo	14.7	8.5	5.8
CSPCo	6.1	6.3	2.3
I&M	4.1	8.2	6.0
KPCo	0.5	1.7	2.2
OPCo	6.3	5.0	6.7
PSO	0.6	0.8	0.7
SWEPCo	1.1	1.7	0.5
TCC	1.9	1.1	5.1
TNC	0.6	0.8	0.4

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 for I&M 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 regulated 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.

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.

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

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 sheet (see "Sale of Receivables" section of Note 16).

Concentrations of Credit Risk and Significant Customers

TNC and TCC have significant customers which on a combined basis account for the following percentages of total Operating Revenues for the periods ended and Accounts Receivable – Customers as of December 31:

	2004	2003	2002
TCC – two customers			
Percentage of Operating Revenues	74%	56%	7%
Percentage of Accounts Receivable - Customers	48	54	N/A
TNC – three customers			
Percentage of Operating Revenues	79	68	9
Percentage of Accounts Receivable - Customers	57	49	N/A

We monitor credit levels and the financial condition of our customers on a continuing basis to minimize credit risk. We believe adequate provision for credit loss has been made in the accompanying Registrant Financial Statements.

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 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, the Registrant Subsidiaries adjust their deferrals and record provisions for estimated refunds to recognize these probable outcomes. For TCC & TNC, their deferred fuel balances will be included in their True-up Proceedings (see Note 6). See Note 5 for the amount of deferred fuel costs by Registrant Subsidiary.

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, Kentucky, Arkansas 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 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. See Note 4 and Note 6 for further information about fuel recovery.

Revenue Recognition

Regulatory Accounting

The financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, CSPCo, OPCo, SWEPCo, TCC and TNC), 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 and 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, Registrant Subsidiaries record them as assets on the balance sheet. Registrant Subsidiaries 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, the Registrant Subsidiaries 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 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).

Beginning in July 2004, as a result of the sale of generation assets in AEP's west zone, AEP is short capacity and must purchase physical power to supply retail and wholesale customers. 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 financial statements on a net basis (see Note 13).

Energy Marketing and Risk Management Activities

Registrant Subsidiaries engage in wholesale electricity and coal and emission allowances marketing and risk management activities. Effective October 2002, these activities were focused on wholesale markets where Registrant Subsidiaries own assets. Registrant Subsidiaries 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, Registrant Subsidiaries 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. Registrant Subsidiaries 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, Registrant Subsidiaries 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. Registrant Subsidiaries 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 financial statements 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).

All of the Registrant Subsidiaries except AEGCo participate in wholesale marketing and risk management activities in electricity and gas. For I&M, KPCo, PSO and a portion of TNC and SWEPCo, when the contract settles the total gain or loss is realized in revenues. Where the revenues are recorded on the income statement depends on whether the contract is subject to the regulated ratemaking process. For contracts subject to the regulated ratemaking process the total gain or loss realized for sales and the cost of purchased energy are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts subject to the regulated ratemaking process are deferred as regulatory liabilities (gains) or regulatory assets (losses). For contracts not subject to the ratemaking process only the difference between the accumulated unrealized net gains or losses recorded in prior periods and the cash proceeds are recognized in the income statement as nonoperating income. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts not subject to the ratemaking process are included in nonoperating income on a net basis. Unrealized mark-to-market gains and losses are included in the balance sheets as Risk Management Assets or Liabilities as appropriate.

For APCo, CSPCo and OPCo, depending on whether the delivery point for the electricity is in the traditional marketing area or not determines where the contract is reported in the income statement. Physical forward risk management sale and purchase contracts with delivery points in the traditional marketing area are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in the traditional marketing area are also included in revenues on a net basis. Physical forward sale and purchase contracts for delivery outside of the traditional marketing area are included in nonoperating income when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of the traditional marketing area are included in nonoperating income on a net basis.

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 financial statements 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 financial statements when the forecasted transaction is realized and affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the financial statements immediately (see Note 13).

Construction Projects for Outside Parties

TCC and TNC 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. Such revenue and related expenses are included in Nonoperating Income and Nonoperating Expenses, respectively, in the financial statements. Contractually billable expenses not yet billed, if significant, are included in Current Assets as Unbilled Construction Costs in the financial statements.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, incremental operation and maintenance costs associated with periodic refueling outages at I&M's Cook Plant are deferred and amortized over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure that all deferred costs are fully amortized by the end of the refueling cycle.

Maintenance Costs

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

Income Taxes and Investment Tax Credits

Registrant Subsidiaries 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

Registrant Subsidiaries, as agents for some state and local governments, collect from customers certain excise taxes levied by those state or local governments on customers. Registrant Subsidiaries do not record 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 Charges.

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.

Registrant Subsidiaries classify instruments that have an unconditional obligation requiring them to redeem the instruments by transferring an asset at a specified date as liabilities on their balance sheets. Those instruments consist of cumulative preferred stock subject to mandatory redemption as of December 31, 2004 and 2003. Beginning July 1, 2003, the Registrant Subsidiaries classify dividends on these mandatorily redeemable preferred shares as Interest Charges. 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, on their financial statements.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain Registrant 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

SWEPCo is the only Registrant Subsidiary with an intangible asset with a finite life and amortizes the asset over its estimated life to its residual value (see Note 3). The Registrant Subsidiaries have no recorded goodwill and intangible assets with indefinite lives as of December 31, 2004 and 2003.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed I&M and TCC 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 Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds for amounts relating to I&M's Cook Plant and are included in Assets Held for Sale-Texas Generation Plants for amounts relating to TCC's ownership in 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). There were no material differences between net income and comprehensive income for AEGCo.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheets in the capitalization section. Accumulated Other Comprehensive Income (Loss) for Registrant Subsidiaries as of December 31, 2004 and 2003 is shown in the following table.

Components	December 31, 2004	December 31, 2003
	(in thousands)	
Cash Flow Hedges:		
APCo	$ (9,324)	$ (1,569)
CSPCo	1,393	202
I&M	(4,076)	222
KPCo	813	420
OPCo	1,241	(103)
PSO	400	156
SWEPCo	(820)	184
TCC	657	(1,828)
TNC	285	(601)
Minimum Pension Liability:		
APCo	$ (72,348)	$ (50,519)
CSPCo	(62,209)	(46,529)
I&M	(41,175)	(25,328)
KPCo	(9,588)	(6,633)
OPCo	(75,505)	(48,704)
PSO	(325)	(43,998)
SWEPCo	(360)	(44,094)
TCC	(4,816)	(60,044)
TNC	(413)	(26,117)

Earnings Per Share (EPS)

AEGCo, APCo, CSPCo, I&M, KPCo and OPCo are wholly-owned subsidiaries of AEP and PSO, SWEPCo, TCC and TNC are owned by a wholly-owned subsidiary of AEP; therefore, none are required to report EPS.

Reclassification

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 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 its 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

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC 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 APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC 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) 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, PSO, SWEPCo and TCC deconsolidated the trusts that held mandatorily redeemable trust preferred securities.

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 our 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" in Note 15).

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 the 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 ITEMS

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 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" and are reflected in TCC's Consolidated Statements of Operations as Extraordinary Loss on Stranded Cost Recovery, Net of Tax.

In 2003 an extraordinary item of $177,000, net of tax of $95,000, was recorded at TNC for the discontinuance of regulatory accounting under SFAS 71 in compliance with a FERC Order dated December 24, 2003 approving a Settlement. The Registrant Subsidiaries had no extraordinary items in 2002.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

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. Registrant Subsidiaries except PSO and AEGCo have recorded after tax charges against net income in Cumulative Effect of Accounting Changes on the Registrant financial statements in the first quarter of 2003. These amounts are recognized as the positions settle.

Asset Retirement Obligations

In the first quarter of 2003, Registrant Subsidiaries except PSO and AEGCo recorded a cumulative effect of accounting change for Asset Retirement Obligations in accordance with SFAS 143.

The following is a summary by Registrant Subsidiary of the cumulative effect of changes in accounting principles recorded in 2003 for the adoptions of SFAS 143 and EITF 02-3 (no effect on AEGCo or PSO):

	SFAS 143 Cumulative Effect		EITF 02-3 Cumulative Effect	
	(in millions)			
	Pretax Income (Loss)	After tax Income (Loss)	Pretax Income (Loss)	After tax Income (Loss)
APCo	$ 128.3	$ 80.3	$ (4.7)	$ (3.0)
CSPCo	49.0	29.3	(3.1)	(2.0)
I&M	-	-	(4.9)	(3.2)
KPCo	-	-	(1.7)	(1.1)
OPCo	213.6	127.3	(4.2)	(2.7)
SWEPCo	13.0	8.4	0.2	0.1
TCC	-	-	0.2	0.1
TNC	4.7	3.1	-	-

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

There is no goodwill carried by any of the Registrant Subsidiaries.

Acquired Intangible Assets

SWEPCo's acquired intangible asset subject to amortization is $18.8 million at December 31, 2004 and $21.7 million at December 31, 2003, net of accumulated amortization and is included in Deferred Charges on the Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization 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)	
Advanced royalties	10	$ 29.4	$ 10.6	$ 29.4	$ 7.7

Amortization of the intangible asset was $2.9 million for 2004 and $3 million for 2003 and 2002. SWEPCo's estimated total amortization is $3 million for each year 2005 through 2010 and $1 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 – Affecting TNC

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 – Affecting TCC

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 the True-up Proceeding. This reconciliation covers the period from July 1998 through December 2001.

On February 3, 2004, the ALJ issued a Proposal for Decision (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, 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 specified 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.

TNC FERC Wholesale Fuel Complaints – Affecting TNC

Certain TNC wholesale customers filed a complaint with the FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs since 1997.

Negotiations to settle the complaint and update the contracts resulted in new contracts. The FERC approved an offer of settlement regarding the fuel complaint and new contracts at market prices in December 2003. Since TNC had recorded a provision for refund in 2002, the effect of the settlement was a $4 million favorable adjustment recorded in December 2003.

SWEPCo Texas Fuel Reconciliation – Affecting SWEPCo

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 – Affecting SWEPCo

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 a review and approval in a future fuel reconciliation.

SWEPCo Louisiana Fuel Audit – Affecting SWEPCo

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 – Affecting PSO

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 Corporation Commission of the State of Oklahoma (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 PSO's revenues, results of operations, cash flows and financial condition.

Virginia Fuel Factor Filing – Affecting APCo

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 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 – Affecting I&M

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, I&M's future results of operations and cash flows would be adversely affected.

Michigan 2004 Fuel Recovery Plan – Affecting I&M

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 – Affecting TCC

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 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 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 – Affecting TCC and TNC

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 TCC's and TNC's future results of operations and cash flows.

TCC Unbundled Cost of Service (UCOS) Appeal – Affecting TCC

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 TCC's future results of operations and cash flows.

SWEPCo Louisiana Compliance Filing – Affecting SWEPCo

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 SWEPCo's future results of operations and cash flows.

SWEPCo Louisiana Service Quality Improvement Program (SQIP) – Affecting SWEPCo

In the 1999 merger proceeding before the LPSC, the LPSC adopted a Service Quality Improvement Program (SQIP) for SWEPCo. On October 8, 2004, SWEPCo filed to amend the SQIP to increase its tree management and trimming expenditures by $5 million above the minimum expenditures currently required by the SQIP and defer these incremental expenses for future rate recovery. On December 9, 2004, the LPSC approved SWEPCo's request to defer the incremental cost of tree management and trimming expenditures beginning December 1, 2004 and ending December 31, 2006 and has authorized SWEPCo to accrue interest based on its weighted average cost of capital. SWEPCo will be permitted to include the deferred costs, including interest, as a cost of service in future base rate proceedings, but only to the extent the deferrals are necessary to allow SWEPCo to recover its authorized return on equity during the time period the expenses were incurred (i.e. an earnings test). The earnings test will not be effective until calendar year 2005. In future rate proceedings, the amortization period will not exceed three years and amortization will commence with the recovery of such costs in base rates.

PSO Rate Review – Affecting PSO

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 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 PSO's revenues, results of operations, cash flows and financial condition.

APCo Virginia Regional Transmission Entity (RTE) Credit Rider – Affecting APCo

Pursuant to a stipulation agreement approved by the Virginia SCC by order dated August 30, 2004 in APCo's Virginia RTO approval proceeding in which APCo requested approval to become a member of PJM, a RTE Credit Rider became effective January 1, 2005. The RTE Credit Rider is designed to reduce APCo's annual Virginia jurisdictional revenues by approximately $2 million. Under the terms of the stipulation agreement, the RTE Credit Rider will be adjusted to produce a $3 million annual Virginia jurisdictional revenue reduction effective on January 1 of the year following the year in which Dominion (Virginia Power) becomes an integrated member of PJM. The RTE Credit Rider will expire at the earlier of December 31, 2010 or upon a change in APCo's base rates as a result of a base rate case filed by APCo.

KPCo Stipulation and Settlement Agreement – Affecting AEGCo, I&M and KPCo

On October 25, 2004, KPCo filed an application requesting the KPSC to approve the terms and provisions of a Stipulation and Settlement Agreement among KPCo, the Office of the Kentucky Attorney General and the Kentucky Industrial Utility Customers. The Stipulation: (1) extends a unit power agreement for approximately 18 years, until December 7, 2022, which obligates KPCo to pay 15 percent of the costs associated with two 1,300 MW generating units in Rockport, Indiana for 15 percent of the units' generating output; (2) modifies KPCo's off-system sales clause tariff to reflect as an expense the environmental costs attributable to off-system sales; and (3) establishes a schedule for KPCo to file its next integrated resource plan, and provides for retail rate recovery of supplemental payments associated with the extension of the unit power agreement and the settlement of other regulatory matters. On December 13, 2004, the KPSC issued its order approving the terms and provisions of the Stipulation and Settlement Agreement. The FERC approved the extension of the unit power agreement on December 29, 2004. KPCo will recover an additional $5 million annually during the first five years and $6 million annually for the remaining 13 years of the 18- year extension.

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, the 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 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 – Affecting KPCo

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 – Affecting APCo, CSPCo, I&M, KPCo and OPCo

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 the AEP East companies 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. Amounts per company are as follows:

Company	(in millions)
APCo	$ 10.5
CSPCo	4.4
I&M	8.0
KPCo	2.4
OPCo	11.9

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, the AEP East companies filed an application with the FERC dividing the RTO formation/integration costs between PJM-incurred integration costs billed to them including related carrying charges, and all other RTO formation/integration costs. AEP East companies intend to file with the FERC to request that deferred PJM-incurred integration costs billed to them be recovered from all PJM customers. Management anticipates 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 the August 2004 application, the AEP East companies 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. The AEP East companies also requested to begin amortizing the deferred PJM-billed integration costs on January 1, 2005, AEP East companies but did not propose an amortization period in the application. The FERC has not ruled on the application.

The AEP East companies integrated into PJM on October 1, 2004. The AEP East companies 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 the AEP East companies) 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. The AEP East companies 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 the AEP East companies 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 the AEP East companies with the opportunity to include such costs in future retail rate filings or the FERC or the state commissions deny recovery of these deferred costs the AEP East companies' future results of operations and cash flows could be adversely affected.

FERC Order on Regional Through and Out Rates – Affecting APCo, CSPCo, I&M, KPCo and OPCo

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 East companies, 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 the AEP East companies previously recovered from 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 East companies for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP East companies accrued $11 million in December 2004 for SECA revenues. On January 7, 2005, AEP East companies 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 AEP's 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 last twelve months prior to the AEP East companies 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 East companies for their 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 – Affecting AEP East companies

In its July 2002 order conditionally accepting the AEP East companies' choice to join PJM, the FERC directed AEP East companies, 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 East companies 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 East companies 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 AEP East companies 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 East companies. 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 East companies 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 East companies 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 East companies 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 – Affecting AEP East and AEP West companies

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 the AEP System 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, the AEP System submitted its generation market power screens in compliance with the FERC's orders. The analysis focused on the three major areas in which AEP subsidiaries serve load and own 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 were filed demonstrated that the AEP System does not possess market power in any of the control areas to which it is directly connected (first-tier markets). The AEP System passed both screening tests in all of its "first tier" markets. In its three "home" control areas, the AEP System passed the pivotal supplier test. The AEP East companies, as part of PJM, also passed the market share screen for the PJM destination market. TCC and TNC also passed the market share screen for ERCOT. PSO, SWEPCo and TNC 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 the conclusions that the AEP System passed both market power screen tests in all areas except SPP. Because the AEP System did not pass the market share screen in SPP, FERC initiated proceedings under Section 206 of the Federal Power Act in which the AEP West companies are rebuttably presumed to possess market power in SPP. Consequently, their 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 management continues to believe the AEP System does not possess market power in SPP, the AEP West companies 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 SPP that encompass the AEP-SPP control area, and make such sales subject to cost-based rate caps. PSO, SWEPCo and TNC have requested the amended tariffs to become effective March 6, 2005.

In addition to FERC market monitoring, the AEP East and West companies are subject to market monitoring oversight by the RTOs in which they are a member, including PJM and SPP. These market monitors have authority for oversight and market power mitigation.

Management believes that the AEP System is 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 at December 31:

	AEGCo			APCo		
	2004	2003	Recovery/ Refund Period	2004	2003	Recovery/ Refund Period
	(in thousands)					
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$ 343,415	$ 325,889	Various Periods (a)
Transition Regulatory Assets – Virginia				25,467	30,855	Up to 6 Years (a)
Unamortized Loss on Reacquired Debt	$ 4,496	$ 4,733	21 Years (b)	18,157	19,005	Up to 28 Years (b)
Asset Retirements Obligations	1,117	928	Various Periods (a)	9,879	9,048	Various Periods (a)
Unrealized Loss on Forward Commitments				13,871	17,006	Various Periods (a)
Other				12,618	15,393	Various Periods (a)
Total Regulatory Assets	$ 5,613	$ 5,661		$ 423,407	$ 417,196	
Regulatory Liabilities:						
Asset Removal Costs	$ 25,428	$ 27,822	(d)	$ 95,763	$ 92,497	(d)
Deferred Investment Tax Credits	46,250	49,589	Up to 18 Years (a)	30,382	30,545	Up to 16 Years (c)
SFAS 109 Regulatory Liability, Net	12,852	15,505	Various Periods (a)			
Over-recovery of Fuel Costs – West Virginia				52,071	55,250	(a)
Unrealized Gain on Forward Commitments				23,270	17,283	Various Periods (a)
Over-recovery of Fuel Costs – Virginia				5,772	13,454	1 Year (b)
Other				-	43	
Total Regulatory Liabilities	$ 84,530	$ 92,916		$ 207,258	$ 209,072	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) A portion of this amount effectively earns a return.
(d) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	CSPCo			I&M		
	2004	2003	Recovery/ Refund Period	2004	2003	Recovery/ Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 16,481	$ 16,027	Various Periods (a)	$ 147,167	$ 151,973	Various Periods (a)
Transition Regulatory Assets	156,676	188,532	Up to 4 Years (a)			
Unamortized Loss on Reacquired Debt	13,155	13,659	Up to 20 Years (b)	21,039	18,424	Up to 28 Years (b)
Incremental Nuclear Refueling Outage Expenses, Net				44,244	57,326	(c)
DOE Decontamination Assessment				14,215	18,863	Up to 3 Years (a)
Other	25,691	24,966	Various Periods (a)	31,015	29,691	Various Periods (a)
Total Regulatory Assets	$ 212,003	$ 243,184		$ 257,680	$ 276,277	
Regulatory Liabilities:						
Asset Removal Costs	$ 103,104	$ 99,119	(d)	$ 280,054	$ 263,015	(d)
Deferred Investment Tax Credits	27,933	30,797	Up to 16 Years (a)	82,802	90,278	Up to 18 Years (a)
Excess ARO for Nuclear Decommissioning				245,175	215,715	(e)
Unrealized Gain on Forward Commitments				35,534	25,010	Various Periods (a)
Other				33,695	36,258	Various Periods (a)
Total Regulatory Liabilities	$ 131,037	$ 129,916		$ 677,260	$ 630,276	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) 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.
(d) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.
(e) 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, which accrues monthly, and will be paid when the nuclear plant is decommissioned.

	KPCo			OPCo		
	2004	2003	Recovery/ Refund Period	2004	2003	Recovery/ Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 103,849	$ 99,828	Various Periods (a)	$ 169,866	$ 169,605	Various Periods (a)
Transition Regulatory Assets				225,273	310,035	3 years (a)
Unamortized Loss on Reacquired Debt	1,021	1,088	Up to 28 Years (b)	11,046	10,172	Up to 34 Years (b)
Other	13,537	12,883	Various Periods (a)	22,189	22,506	Various Periods (a)
Total Regulatory Assets	$ 118,407	$ 113,799		$ 428,374	$ 512,318	
Regulatory Liabilities:						
Asset Removal Costs	$ 28,232	$ 26,140	(c)	$ 102,875	$ 101,160	(c)
Deferred Investment Tax Credits	6,722	7,955	Up to 16 Years (a)	12,539	15,641	Up to 16 Years (a)
Unrealized Gain on Forward Commitments	13,041	9,174	Various Periods (a)			
Other	2,581	1,417	Various Periods (a)	-	3	
Total Regulatory Liabilities	$ 50,576	$ 44,686		$ 115,414	$ 116,804	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	PSO			SWEPCo		
	2004	2003	Recovery/ Refund Period	2004	2003	Recovery/ Refund Period
	(in thousands)					
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$ 18,000	$ 3,235	Various Periods (b)
Under-recovered Fuel Costs	$ 366	$ 24,170	1 Year (a)	4,687	11,394	1 Year (a)
Unamortized Loss on Reacquired Debt	14,705	14,357	Up to 11 Years (b)	20,765	19,331	Up to 39 Years (b)
Other	17,246	14,342	Various Periods (d)	16,350	15,859	Various Periods (c)
Total Regulatory Assets	$ 32,317	$ 52,869		$ 59,802	$ 49,819	
Regulatory Liabilities:						
Asset Removal Costs	$ 220,298	$ 214,033	(e)	$ 249,892	$ 236,409	(e)
Deferred Investment Tax Credits	28,620	30,411	Up to 25 Years (d)	35,539	39,864	Up to 13 Years (d)
SFAS 109 Regulatory Liability, Net	21,963	24,937	Various Periods (b)			
Over-recovered Fuel Costs				9,891	4,178	1 Year (a)
Excess Earnings				3,167	2,600	(d)
Unrealized Gain on Forward Commitments	19,676	15,406	Various Periods (d)	15,176	11,793	Various Periods (d)
Other				6,144	6,986	Various Periods (c)
Total Regulatory Liabilities	$ 290,557	$ 284,787		$ 319,809	$ 301,830	

(a) Over/Under-recovered fuel for PSO's Oklahoma jurisdiction & SWEPCo's Arkansas and Louisiana jurisdictions does not earn a return. Texas jurisdictional amounts for SWEPCo do earn a return.
(b) Amount effectively earns a return.
(c) Amounts are both earning and not earning a return.
(d) Amount does not earn a return.
(e) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	TCC			TNC		
	2004	2003	Recovery/ Refund Period	2004	2003	Recovery/ Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 15,236	$ 3,249	Various Periods (a)			
Designated for Securitization	1,361,299	1,289,436	(b)			
Under Recovery of Fuel Costs				$ -	$ 6,180	(c)
Wholesale Capacity Auction True-up	559,973	480,000	(c)			
Unamortized Loss on Reacquired Debt	11,842	9,086	Up to 32 Years (a)	2,147	3,929	Up to 15 Years (a)
Deferred Debt - Restructuring	11,596	12,015	Up to 14 Years (a)	6,093	6,579	Up to 14 Years (a)
Other	102,032	127,488	Various Periods (e)	3,783	3,332	Various Periods (e)
Total Regulatory Assets	$ 2,061,978	$ 1,921,274		$ 12,023	$ 20,020	
Regulatory Liabilities:						
Asset Removal Costs	$ 102,624	$ 95,415	(f)	$ 81,143	$ 76,740	(f)
Deferred Investment Tax Credits	107,743	112,479	Up to 24 Years (d)	18,698	19,990	Up to 18 Years (d)
Over-recovery of Fuel Costs	211,526	150,026	(c)	3,920	-	(c)
Retail Clawback	61,384	45,527	(c)	13,924	11,804	(c)
Over-recovery of Transition Charges	14,522	22,499	Up to 12 Years (a)			
Excess Earnings				13,270	14,262	Up to 30 Years (a)
SFAS 109 Regulatory Liability, Net				8,500	13,655	Various Periods (a)
Other	62,131	64,207	Various Periods (e)	1,319	1,826	Various Periods (e)
Total Regulatory Liabilities	$ 559,930	$ 490,153		$ 140,774	$ 138,277	

(a) Amount earns 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 Note 6 "Texas Restructuring" and "Carrying Costs on Net True-up Regulatory Assets" 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 does not earn a return.
(e) Amounts are both earning and not earning a return.
(f) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

Texas Restructuring Related Regulatory Assets and Liabilities

Designated for Securitization, Wholesale Capacity Auction True-up regulatory assets, Over-recovery of Fuel Costs and Retail Clawback regulatory liabilities are not being currently 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. In connection with the merger, nonrecoverable merger costs were expensed in 2003 and 2002. Such costs included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were nonrecoverable change in control payments. Merger transaction and transition costs recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements. The deferred merger costs are being amortized over five to eight year recovery periods, depending on the specific terms of the settlement agreements, with the amortization included in depreciation and amortization expense. Deferred merger costs are included in Other Regulatory Assets in the above tables.

As hereinafter summarized, the state settlement agreements provide for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions which began in the third quarter of 2000.

Summary of key provisions of Merger Rate Agreements:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	Rate reductions of $221 million over 6 years.
Indiana – I&M	Rate reductions 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 Registrant Subsidiaries operate. The following paragraphs discuss significant events related to industry restructuring in those states.

OHIO RESTRUCTURING – Affecting CSPCo and OPCo

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 a 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 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 $8 million and $21 million, repectively, 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.

As provided in stipulation agreements approved by the PUCO in 2000, CSPCo and OPCo are deferring customer choice implementation costs and related carrying costs in excess of $20 million per company. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. Through December 31, 2004, CSPCo has incurred $38 million and deferred $18 million and OPCo has incurred $40 million and deferred $20 million of 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 plans, 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 - *Affecting SWEPCo, TCC and TNC*

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 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. TCC received bids for all of its 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 NRC. 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 Asset" 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 Stranded Cost Recovery, Net of Tax in TCC's Consolidated Statements of Income. Management believes that with these adjustments to TCC's stranded generation plant costs regulatory asset, they have 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 cost, 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 TCC's Consolidated Statements of Income.

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 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 deferred 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 Stranded Cost Recovery in TCC's Consolidated Statements of Income. 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. Management believes that TCC's 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 management intends to seek vigorously its recovery. If, however, management determines 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 is able to estimate the amount of such nonrecovery, TCC 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 their 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 - *Affecting I&M*

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 - *Affecting APCo*

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 - *Affecting SWEPCo*

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 - *Affecting APCo*

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 – Affecting APCo, CSPCo, I&M, and OPCo

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 AEP 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 subsidiaries filed an answer to the complaint in January 2005, denying the allegations and stating their 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 AEP 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. Management believes the allegations in the complaint are without merit, and intends 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.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. Management is 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 AEP subsidiaries 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.

Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo

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 – Affecting AEP System

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 – Affecting I&M and TCC

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 – Affecting I&M and TCC

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 – Affecting I&M and TCC

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 – Affecting I&M and TCC

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 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 its Consolidated Balance Sheets.

OPERATIONAL

Construction and Commitments – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The AEP System has substantial construction commitments to support its operations. The following table shows the estimated construction expenditures by company for 2005 including amounts for proposed environmental rules:

	(in millions)
AEGCo	$ 19.9
APCo	696.7
CSPCo	193.9
I&M	322.8
KPCo	56.1
OPCo	765.6
PSO	126.2
SWEPCo	200.9
TCC	208.5
TNC	73.9

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

AEP subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The expiration date of the longest fuel contract is 2010 for APCo, 2008 for CSPCo, 2014 for I&M, 2008 for KPCo, 2012 for OPCo, 2007 for PSO and 2012 for SWEPCo. The contracts provide for periodic price adjustments and contain various clauses that would release us from our obligations under certain conditions.

I&M 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 – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

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 – Affecting OPCo

AEP has 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 AEP. AEP has 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.

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 OPCo separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. OPCo alleges that TEM has breached the PPA, and is seeking a determination of OPCo's 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 OPCo's breaches. If the PPA is deemed terminated or found to be unenforceable by the court, OPCo could be adversely affected to the extent it is unable to find other purchasers of the power with similar contractual terms and to the extent OPCo does not fully recover claimed termination value damages from TEM. However, OPCo has entered into an agreement with an affiliate that eliminates OPCo's market exposure related to the PPA. 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 OPCo 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.

Merger Litigation – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

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 – Affecting APCo, CSPCo, I&M, KPCo and OPCo

In 2002, certain subsidiaries of AEP 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 subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy.

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 asserted its right to offset trading payables owed to various Enron entities against trading receivables due to several AEP 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.

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 the offsetting of receivables and payables. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on results of operations, cash flows or financial condition.

Texas Commercial Energy, LLP Lawsuit – Affecting TCC and TNC

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against AEP and four AEP subsidiaries, including TCC and TNC, certain nonaffiliated energy companies and ERCOT. 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. AEP and its subsidiaries filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. AEP and its subsidiaries 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.

Coal Transportation Dispute – Affecting PSO, TCC and TNC

PSO, TCC, TNC and two nonaffiliated entities, as joint owners of a generating station, have disputed transportation costs for coal received between July 2000 and the present time. The joint plant has 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, PSO, as operator of the plant, recorded a provision for possible loss in December 2004. The provision was deferred as a regulatory asset under PSO's fuel mechanism and affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

FERC Long-term Contracts – Affecting AEP East and AEP West Companies

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 AEP subsidiaries 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.

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

Certain Registrant Subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs cover insurance programs, security deposits, debt service reserves, and credit enhancements for issued bonds. All of these LOCs were issued in the subsidiaries' ordinary course of business. At December 31, 2004, the maximum future payments of the LOCs include $44 million, $1 million, $51 million, $4 million and $43 million for CSPCo, I&M, OPCo, SWEPCo and TCC, respectively, with maturities ranging from March 2005 to April 2007. There is no recourse to third parties in the event these letters of credit are drawn.

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.

On 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

All of the Registrant Subsidiaries enter into certain 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, exposure generally does not exceed the sale price. Registrant Subsidiaries 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, Registrant Subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary except for TCC which entered an indemnification of $129 million relating to the sale of its generation assets in July 2004 (see "Texas Plants – TCC and TNC Generation Assets" section of Note 10). 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.

Registrant Subsidiaries are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East and West companies and for activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Certain Registrant Subsidiaries 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, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2004, the maximum potential loss by subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Subsidiary	Maximum Potential Loss (in millions)
APCo	$ 5
CSPCo	2
I&M	3
KPCo	1
OPCo	4
PSO	4
SWEPCo	4
TCC	6
TNC	3

9. SUSTAINED EARNINGS IMPROVEMENT INITIATIVE

In response to difficult conditions in AEP's 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.

The Registrant Subsidiaries recorded termination benefits expense relating to 389 terminated employees totaling $57.9 million pretax in the fourth quarter of 2002. Of this amount, the Registrant Subsidiaries paid $5.0 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 Other Operation expense on the Registrant Subsidiaries' statements of operations. Management determined that the termination of the employees under the SEI initiative did not constitute a plan curtailment of any of the retirement benefit plans.

The following table shows the staff reductions, termination benefits expense and the remaining termination benefits expense accrual as of December 31, 2002:

	Total Number of Terminated Employees	Total Expense Recorded in 2002 (in millions)	Total Termination Benefits Accrued at December 31, 2002 (in millions)
AEGCo	-	$ 0.3	$ 0.3
APCo	93	13.1	12.2
CSPCo	19	5.0	4.5
I&M	146	15.0	13.1
KPCo	16	2.6	2.5
OPCo	33	7.5	7.1
PSO	17	3.1	3.0
SWEPCo	8	3.3	3.1
TCC	37	6.0	5.5
TNC	20	2.0	1.6

10. DISPOSITIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

DISPOSITIONS

2004

Texas Plants – TCC and TNC Generation Assets

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 new RMR contracts at 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 TNC plants, a pretax write-down of utility assets of approximately $34 million was recorded in Asset Impairments expense during the third quarter of 2002 on TNC's 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 TCC's 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 expense of $4 million in the fourth quarter of 2002. In addition, TNC recorded related inventory write-downs of $3 million ($1 million of fuel inventory in Fuel for Electric Generation expense and $1 million of materials and supplies recorded in Other Operation expense). Similarly, TCC recorded an additional pretax asset impairment write-down of $7 million, which was deferred and recorded in Regulatory Assets Designated for Securitization 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 related to TNC is included in Asset Impairments expense in TNC's Statements of Operations.

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as "reliability-must-run" status.

During the fourth quarter of 2003, after receiving indicative bids from interested buyers, TCC recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to Assets Held for Sale – Texas Generation Plants on TCC's Consolidated Balance Sheets. In accordance with Texas Restructuring 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 TCC is unable to recover all or a portion of its requested costs (see "Net Stranded Generation Costs" section of Note 6), any unrecovered costs could have a material adverse effect on TCC's results of operations, cash flows and possibly financial condition.

In March 2004, TCC 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 TCC's results of operations during the period ending December 31, 2004.

In December 2004, TCC recorded a $185 pretax deduction ($121 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 TCC's 2004 Consolidated Statements of Income.

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 TCC's Consolidated Balance Sheets.

2003

Water Heater Assets – APCo, CSPCo, I&M, KPCo and OPCo

APCo, CSPCo, I&M, KPCo and OPCo participated in 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. We sold our water heater rental program and recorded a pretax loss in the first quarter of 2003 based upon final terms of the sale agreement. We provided for pretax charges in the fourth quarter of 2002 based on an estimated sales price. See below for amounts by company:

Subsidiary Company	Asset Impairment Charge Recorded in Fourth Quarter 2002 (Pretax)	Lease Prepayment Penalty Recorded in Fourth Quarter 2002 (Pretax)	Loss on Sale Recorded in First Quarter 2003 (Pretax)
		(in millions)	
APCo	$ 0.050	$ 0.062	$ 0.056
CSPCo	0.615	0.758	0.740
I&M	0.643	0.792	0.787
KPCo	0.011	0.011	0.011
OPCo	1.757	2.163	2.165

Ft. Davis Wind Farm – TNC

In the 1990's, TNC developed a 6 MW facility wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002, TNC's 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 on TNC's Statements of Operations.

ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station

In January 2004, TCC signed an agreement to sell its 7.81% share of Oklaunion Power Station for approximately $43 million, subject to closing adjustments, to an unrelated party. In May 2004, TCC 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, TCC entered into sales agreements with both of its 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 TCC 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. TCC cannot predict when these issues will be resolved. TCC does not expect the sale to have a significant effect on its future results of operations. TCC's assets and liabilities related to the Oklaunion Power

Station have been classified as Assets Held for Sale – Texas Generation Plants and Liabilities Held for Sale – Texas Generation Plants, respectively, in TCC's Consolidated Balance Sheets.

Texas Plants – South Texas Project

In February 2004, TCC signed an agreement to sell its 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, TCC 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, TCC entered into sales agreements with two of its nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. TCC does not expect the sale to have a significant effect on its future results of operations. TCC expects the sale to close in the first six months of 2005. TCC's assets and liabilities related to STP have been classified as Assets Held for Sale – Texas Generation Plants and Liabilities Held for Sale – Texas Generation Plants, respectively, in TCC's Consolidated Balance Sheets as of December 31, 2004 and 2003.

The assets and liabilities of the entities held for sale at December 31, 2004 and 2003 are as follows:

	Texas Plants (TCC) December 31,	
	2004	2003
	(in millions)	
Assets:		
Current Assets	$ 24	$ 57
Property, Plant and Equipment, Net	413	797
Regulatory Assets	48	49
Nuclear Decommissioning Trust Fund	143	125
Total Assets Held for Sale – Texas Generation Plants	$ 628	$ 1,028
Liabilities:		
Regulatory Liabilities – Other	$ 1	$ 9
Asset Retirement Obligations	249	219
Total Liabilities Held for Sale – Texas Generation Plants	$ 250	$ 228

ASSETS HELD AND USED

Blackhawk Coal Company – I&M

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 Nonoperating Expenses in I&M's Consolidated Statements of Income.

11. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and life insurance benefits for retired employees in the U.S. APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC 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 the 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.

The following table provides the reduction in the net periodic postretirement cost for 2004 for the Registrant Subsidiaries:

	Postretirement Benefit Cost Reduction
	(in thousands)
APCo	$ 5,208
CSPCo	2,417
I&M	3,647
KPCo	690
OPCo	4,106
PSO	1,520
SWEPCo	1,571
TCC	1,849
TNC	770

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:

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) AEP's 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 AEP's 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 percentages)		
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 AEP's 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 percentages)		
Equity Securities	70	70	61
Debt Securities	28	28	36
Other	2	2	3
Total	100	100	100

AEP's investment strategy for their 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. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to the 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 AEP's 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).

AEP bases its 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:

AEP's combined pension funds are underfunded in total (plan assets are less than projected benefit obligations) by $553 million at December 31, 2004. For AEP's 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:

	Underfunded Pension Plans	
End of Year	2004	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	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)

AEP made an additional discretionary contribution of $200 million in the fourth quarter of 2004 and intends to make additional discretionary contributions of approximately $100 million per quarter in 2005 to meet its 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 AEP's benefit obligations are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	2003	2004	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 AEP utilizes 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, AEP changed to a duration based method where a hypothetical portfolio of high quality corporate bonds was constructed with a duration similar to the duration of 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:

	Pension Plans		Other Postretirement Benefit Plans	
Employer Contributions	**2005**	**2004**	**2005**	**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 AEP's 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 AEP's assets, including both AEP's 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	Other Postretirement Benefit Plans	
	Pension Payments	**Benefit Payments**	**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 AEP's 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

Net Pension Cost by Registrant:

The following table provides the net periodic benefit cost (credit) for the plans by the following Registrant Subsidiaries for fiscal years 2004, 2003 and 2002:

	Pension Plans			Other Postretirement Benefit Plans		
	2004	2003	2002	2004	2003	2002
			(in thousands)			
APCo	$ 1,272	$ (5,202)	$ (9,988)	$ 25,783	$ 33,682	$ 25,153
CSPCo	(1,626)	(5,399)	(8,328)	11,050	14,684	11,494
I&M	4,460	(812)	(4,149)	17,259	22,999	17,608
KPCo	571	(566)	(1,405)	2,961	4,043	2,986
OPCo	(128)	(6,621)	(11,327)	21,038	28,208	22,654
PSO	2,795	(291)	(3,708)	8,449	9,885	8,436
SWEPCo	3,602	1,018	(2,162)	8,400	10,264	8,371
TCC	2,987	(123)	(4,560)	10,144	12,951	10,733
TNC	1,351	606	(993)	4,280	5,875	4,798

Actuarial Assumptions for Net Periodic Benefit Costs:

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

	Pension Plans			Other Postretirement Benefit Plans		
	2004	2003	2002	2004	2003	2002
			(in percentages)			
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)

Retirement Savings Plan

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in an AEP sponsored defined contribution retirement savings plan eligible to substantially all non-United Mine Workers of America (UMWA) employees. This plan includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. Prior to January 1, 2003, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participated in two large AEP sponsored defined contribution retirement savings plans. The contributions to the plan are 75% of the first 6% of eligible employee compensation.

The following table provides the cost for contributions to the retirement savings plans by the following Registrant Subsidiaries for fiscal years 2004, 2003 and 2002:

	2004	2003	2002
		(in thousands)	
APCo	$ 6,538	$ 6,450	$ 6,722
CSPCo	2,723	2,745	2,784
I&M	7,262	7,616	8,039
KPCo	1,030	1,042	1,043
OPCo	5,688	5,719	5,785
PSO	2,731	2,350	2,260
SWEPCo	3,571	3,418	3,170
TCC	2,544	2,757	3,054
TNC	1,126	1,332	1,574

Other UMWA Benefits

OPCo provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UWMA 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 AEP and benefits are paid from AEP's 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. BUSINESS SEGMENTS

All of AEP's Registrant Subsidiaries have one reportable segment. The one reportable segment is a vertically integrated electricity generation, transmission and distribution business except AEGCo, an electricity generation business. All of the Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on the business process, cost structures and operating results.

13. 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.

Registrant Subsidiaries' 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 Registrant Financial Statements. 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.

The Registrant Subsidiaries designate the hedging instrument, based on the exposure being hedged, as a fair value hedge or cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), Registrant Subsidiaries 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 Registrant Financial Statements 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), Registrant Subsidiaries 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 Registrant Financial Statements 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.

Fair Value Hedging Strategies

Certain Registrant Subsidiaries 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 exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. Registrant Subsidiaries do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

Certain Registrant Subsidiaries 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. Registrant Subsidiaries do not hedge all foreign currency exposure.

Certain Registrant Subsidiaries enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. These transactions effectively modify exposure to interest risk by converting a portion of floating-rate debt to a fixed rate. During 2004, certain Registrant Subsidiaries 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. Registrant Subsidiaries do not hedge all interest rate exposure. During 2004, APCO and I&M reclassified immaterial amounts to earnings because the original forecasted transaction did not occur within the originally specified time period.

Registrant Subsidiaries enter into, and designate as cash flow hedges, certain forward and swap transactions for the purchase and sale of electricity to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impact of commodity price changes and, where appropriate, enter into contracts to protect margin for a portion of future sales and generation revenues. Registrant Subsidiaries do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity. During 2004, certain Registrant Subsidiaries classified immaterial amounts into earnings as a result of hedge ineffectiveness related to cash flow hedging strategies.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges for the years 2002, 2003 and 2004:

		(in thousands)
APCo		
Beginning Balance at December 31, 2001	$	(340)
Effective portion of changes in fair value		(1,310)
Reclasses from AOCI to net income		(270)
Balance at December 31, 2002		(1,920)
Effective portion of changes in fair value		(448)
Reclasses from AOCI to net income		799
Balance at December 31, 2003		(1,569)
Effective portion of changes in fair value		(6,269)
Reclasses from AOCI to net income		(1,486)
Ending Balance, December 31, 2004	$	(9,324)
CSPCo		
Beginning Balance at December 31, 2001	$	-
Effective portion of changes in fair value		62
Reclasses from AOCI to net income		(329)
Balance at December 31, 2002		(267)
Effective portion of changes in fair value		194
Reclasses from AOCI to net income		275

Balance at December 31, 2003	202
Effective portion of changes in fair value	2,304
Reclasses from AOCI to net income	(1,113)
Ending Balance, December 31, 2004	$ 1,393
I&M	
Beginning Balance at December 31, 2001	$ (3,835)
Effective portion of changes in fair value	34
Reclasses from AOCI to net income	3,515
Balance at December 31, 2002	(286)
Effective portion of changes in fair value	209
Reclasses from AOCI to net income	299
Balance at December 31, 2003	222
Effective portion of changes in fair value	(3,141)
Reclasses from AOCI to net income	(1,157)
Ending Balance, December 31, 2004	$ (4,076)
KPCo	
Beginning Balance at December 31, 2001	$ (1,903)
Effective portion of changes in fair value	343
Reclasses from AOCI to net income	1,882
Balance at December 31, 2002	322
Effective portion of changes in fair value	75
Reclasses from AOCI to net income	23
Balance at December 31, 2003	420
Effective portion of changes in fair value	918
Reclasses from AOCI to net income	(525)
Ending Balance, December 31, 2004	$ 813
OPCo	
Beginning Balance at December 31, 2001	$ (196)
Effective portion of changes in fair value	(103)
Reclasses from AOCI to net income	(439)
Balance at December 31, 2002	(738)
Effective portion of changes in fair value	256
Reclasses from AOCI to net income	379
Balance at December 31, 2003	(103)
Effective portion of changes in fair value	2,830
Reclasses from AOCI to net income	(1,486)
Ending Balance, December 31, 2004	$ 1,241
PSO	
Beginning Balance at December 31, 2001	$ -
Effective portion of changes in fair value	2
Reclasses from AOCI to net income	(44)
Balance at December 31, 2002	(42)
Effective portion of changes in fair value	18
Reclasses from AOCI to net income	180
Balance at December 31, 2003	156
Effective portion of changes in fair value	713
Reclasses from AOCI to net income	(469)
Ending Balance, December 31, 2004	$ 400
SWEPCo	
Beginning Balance at December 31, 2001	$ -
Effective portion of changes in fair value	1
Reclasses from AOCI to net income	(49)

Balance at December 31, 2002	(48)
Effective portion of changes in fair value	21
Reclasses from AOCI to net income	211
Balance at December 31, 2003	184
Effective portion of changes in fair value	(450)
Reclasses from AOCI to net income	(554)
Ending Balance, December 31, 2004	$ (820)
TCC	
Beginning Balance at December 31, 2001	$ -
Effective portion of changes in fair value	30
Reclasses from AOCI to net income	(66)
Balance at December 31, 2002	(36)
Effective portion of changes in fair value	(1,931)
Reclasses from AOCI to net income	139
Balance at December 31, 2003	(1,828)
Effective portion of changes in fair value	866
Reclasses from AOCI to net income	1,619
Ending Balance, December 31, 2004	$ 657
TNC	
Beginning Balance at December 31, 2001	$ -
Effective portion of changes in fair value	3
Reclasses from AOCI to net income	(18)
Balance at December 31, 2002	(15)
Effective portion of changes in fair value	(641)
Reclasses from AOCI to net income	55
Balance at December 31, 2003	(601)
Effective portion of changes in fair value	373
Reclasses from AOCI to net income	513
Ending Balance, December 31, 2004	$ 285

The following table approximates net gains from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2004 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is fourteen months.

	(in thousands)
APCo	$ 1,876
CSPCo	1,750
I&M	1,386
KPCo	800
OPCo	2,083
PSO	1,182
SWEPCo	1,413
TCC	825
TNC	357

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 could be realized in a current market exchange.

The book values and fair values of significant financial instruments for Registrant Subsidiaries at December 31, 2004 and 2003 are summarized in the following tables.

	2004		2003	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
AEGCo				
Long-term Debt	$ 44,820	$ 46,249	$ 44,811	$ 47,882
APCo				
Long-term Debt	1,784,598	1,822,687	1,864,081	1,926,518
Cumulative Preferred Stock Subject to Mandatory Redemption	-	-	5,360	5,287
CSPCo				
Long-term Debt	987,626	1,040,885	897,564	938,595
I&M				
Long-term Debt	1,312,843	1,349,614	1,339,359	1,400,937
Cumulative Preferred Stock Subject to Mandatory Redemption	61,445	61,637	63,445	63,293
KPCo				
Long-term Debt	508,310	521,776	487,602	503,704
OPCo				
Long-term Debt	2,011,060	2,092,645	2,039,940	2,117,131
Cumulative Preferred Stock Subject to Mandatory Redemption	5,000	5,016	7,250	7,214
PSO				
Long-term Debt	546,092	557,630	574,298	589,956
SWEPCo				
Long-term Debt	805,369	833,246	884,308	917,982
TCC				
Long-term Debt	1,907,294	2,013,546	2,291,625	2,393,468
TNC				
Long-term Debt	314,357	329,514	356,754	374,420

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments are classified as available for sale for decommissioning (I&M, TCC) and SNF disposal for I&M. I&M reports trusts in "Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds" on its Consolidated Balance Sheets. TCC reports trusts in "Assets Held for Sale – Texas Generating Plants" on its Consolidated Balance Sheets. The following table provides fair values, cost basis and net unrealized gains or losses at December 31:

	I&M		TCC	
	2004	2003	2004	2003
	(in thousands)			
Fair Value	$ 1,053,400	$ 982,400	$ 143,200	$ 124,700
Cost Basis	936,500	900,000	107,000	94,800

	I&M			TCC		
	2004	2003	2002	2004	2003	2002
	(in thousands)					
Net Unrealized Holding Gain (Loss)	$ 34,500	$ 35,500	$ (25,400)	$ 6,400	$ 16,700	$ (7,500)

14. INCOME TAXES

The details of the Registrant Subsidiaries' income taxes before extraordinary loss and cumulative effect of accounting changes as reported are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo
	(in thousands)				
Year Ended December 31, 2004					
Charged (Credited) to Operating Expenses (net):					
Current	$ 5,729	$ 34,721	$ 54,287	$ 79,645	$ (4,697)
Deferred	(2,187)	55,347	17,945	(1,784)	14,925
Deferred Investment Tax Expense (Credits)	-	1,010	(2,864)	(7,476)	(1,233)
Total	3,542	91,078	69,368	70,385	8,995
Charged (Credited) to Nonoperating Income (net):					
Current	(287)	2,968	2,853	4,994	1,827
Deferred	(32)	(7,762)	(4,550)	(3,764)	(2,151)
Deferred Investment Tax Credits	(3,339)	(1,173)	-	-	-
Total	(3,658)	(5,967)	(1,697)	1,230	(324)
Total Income Tax as Reported	$ (116)	$ 85,111	$ 67,671	$ 71,615	$ 8,671

	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Year Ended December 31, 2004					
Charged (Credited) to Operating Expenses (net):					
Current	$ 69,576	$ (12,315)	$ 26,618	$ 117,667	$ 16,693
Deferred	30,080	23,226	14,166	(86,034)	5,272
Deferred Investment Tax Credits	(2,498)	(1,791)	(4,326)	(4,736)	(1,292)
Total	97,158	9,120	36,458	26,897	20,673
Charged (Credited) to Nonoperating Income (net):					
Current	6,307	(119)	(347)	5,637	2,872
Deferred	(6,751)	(1,192)	(1,384)	102,524	(1,036)
Deferred Investment Tax Credits	(604)	-	-	-	-
Total	(1,048)	(1,311)	(1,731)	108,161	1,836
Total Income Tax as Reported	$ 96,110	$ 7,809	$ 34,727	$ 135,058	$ 22,509

	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Year Ended December 31, 2003					
Charged (Credited) to Operating Expenses (net):					
Current	$ 7,481	$ 84,449	$ 83,469	$ 58,190	$ (7,840)
Deferred	(5,838)	37,024	3,982	66	21,183
Deferred Investment Tax Credits	-	(1,884)	(3,041)	(7,330)	(1,168)
Total	1,643	119,589	84,410	50,926	12,175
Charged (Credited) to Nonoperating Income (net):					
Current	(196)	(646)	(2,183)	5,283	(1,382)
Deferred	-	(12,461)	(8,496)	(14,960)	(1,076)
Deferred Investment Tax Credits	(3,354)	(1,262)	(69)	(101)	(42)
Total	(3,550)	(14,369)	(10,748)	(9,778)	(2,500)
Total Income Tax as Reported	$ (1,907)	$ 105,220	$ 73,662	$ 41,148	$ 9,675

	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Year Ended December 31, 2003					
Charged (Credited) to Operating Expenses (net):					
Current	$ 116,316	$ 55,834	$ 51,564	$ 88,530	$ 33,822
Deferred	32,191	(17,036)	7,230	14,769	(5,113)
Deferred Investment Tax Credits	(2,493)	(1,790)	(4,326)	(5,207)	(1,520)
Total	146,014	37,008	54,468	98,092	27,189
Charged (Credited) to Nonoperating Income (net):					
Current	708	(1,566)	(6,108)	2,456	1,454
Deferred	(7,709)	2,395	2,712	4,624	1,620
Deferred Investment Tax Credits	(614)	-	-	-	-
Total	(7,615)	829	(3,396)	7,080	3,074
Total Income Tax as Reported	$ 138,399	$ 37,837	$ 51,072	$ 105,172	$ 30,263

	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Year Ended December 31, 2002					
Charged (Credited) to Operating Expenses (net):					
Current	$ 6,607	$ 99,140	$ 81,538	$ 66,063	$ 680
Deferred	(5,028)	17,626	25,771	(19,870)	9,451
Deferred Investment Tax Expense (Credits)	2	(3,229)	(3,095)	(7,340)	(1,173)
Total	1,581	113,537	104,214	38,853	8,958
Charged (Credited) to Nonoperating Income (net):					
Current	(173)	(354)	9,442	3,435	1,583
Deferred	-	(849)	(2,479)	2,949	388
Deferred Investment Tax Credits	(3,363)	(1,408)	(174)	(400)	(67)
Total	(3,536)	(2,611)	6,789	5,984	1,904
Total Income Tax as Reported	$ (1,955)	$ 110,926	$ 111,003	$ 44,837	$ 10,862

	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Year Ended December 31, 2002					
Charged (Credited) to Operating Expenses (net):					
Current	$ 86,026	$ (49,673)	$ 41,354	$ 30,494	$ 109
Deferred	30,048	75,659	(3,134)	113,726	(10,652)
Deferred Investment Tax Credits	(2,493)	(1,791)	(4,524)	(5,206)	(1,271)
Total	113,581	24,195	33,696	139,014	(11,814)
Charged (Credited) to Nonoperating Income (net):					
Current	2,732	(1,812)	1,772	3,223	1,334
Deferred	15,962	-	-	(71)	(1,623)
Deferred Investment Tax Credits	(684)	-	-	-	-
Total	18,010	(1,812)	1,772	3,152	(289)
Total Income Tax as Reported	$ 131,591	$ 22,383	$ 35,468	$ 142,166	$ (12,103)

Shown below is a reconciliation for each Registrant Subsidiary of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Year Ended December 31, 2004					
Net Income	$ 7,842	$ 153,115	$ 140,258	$ 133,222	$ 25,905
Income Taxes	(116)	85,111	67,671	71,615	8,671
Pretax Income	$ 7,726	$ 238,226	$ 207,929	$ 204,837	$ 34,576
Income Tax on Pretax Income at Statutory Rate (35%)	$ 2,704	$ 83,379	$ 72,775	$ 71,693	$ 12,102
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	808	10,719	2,570	19,023	1,466
Nuclear Fuel Disposal Costs	-	-	-	(3,338)	-
Allowance for Funds Used During Construction	(1,060)	(3,948)	(515)	(3,160)	(603)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(1,632)	(336)	(2,974)	(1,497)
Investment Tax Credits (net)	(3,339)	(163)	(2,864)	(7,476)	(1,233)
State and Local Income Taxes	933	6,629	159	7,102	(197)
Other	(536)	(9,873)	(4,118)	(9,652)	(1,367)
Total Income Taxes as Reported	$ (116)	$ 85,111	$ 67,671	$ 71,615	$ 8,671
Effective Income Tax Rate	N.M.	35.7%	32.5%	35.0%	25.1%

N.M. = Not Meaningful

	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Year Ended December 31, 2004					
Net Income	$ 210,116	$ 37,542	$ 89,457	$ 174,122	$ 47,659
Extraordinary Loss	-	-	-	120,534	-
Income Taxes	96,110	7,809	34,727	135,058	22,509
Pretax Income	$ 306,226	$ 45,351	$ 124,184	$ 429,714	$ 70,168
Income Tax on Pretax Income at Statutory Rate (35%)	$ 107,179	$ 15,873	$ 43,464	$ 150,400	$ 24,559
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	4,977	(937)	(1,622)	(812)	(739)
Investment Tax Credits (net)	(3,102)	(1,791)	(4,326)	(4,736)	(1,292)
State and Local Income Taxes	305	1,882	4,736	543	2,762
Other	(13,249)	(7,218)	(7,525)	(10,337)	(2,781)
Total Income Taxes as Reported	$ 96,110	$ 7,809	$ 34,727	$ 135,058	$ 22,509
Effective Income Tax Rate	31.4%	17.2%	28.0%	31.4%	32.1%

	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Year Ended December 31, 2003					
Net Income	$ 7,964	$ 280,040	$ 200,430	$ 86,388	$ 32,330
Cumulative Effect of Accounting Changes	-	(77,257)	(27,283)	3,160	1,134
Income Taxes	(1,907)	105,220	73,662	41,148	9,675
Pretax Income	$ 6,057	$ 308,003	$ 246,809	$ 130,696	$ 43,139
Income Tax on Pretax Income at Statutory Rate (35%)	$ 2,120	$ 107,801	$ 86,383	$ 45,744	$ 15,099
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	371	9,209	2,220	17,735	1,538
Nuclear Fuel Disposal Costs	-	-	-	(6,465)	-
Allowance for Funds Used During Construction	(1,053)	(2,048)	(232)	(4,127)	(851)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(2,280)	(7)	(693)	(735)
Investment Tax Credits (net)	(3,354)	(3,146)	(3,110)	(7,431)	(1,210)
State and Local Income Taxes	372	1,123	(3,074)	4,634	(58)
Other	(737)	(5,439)	(8,518)	(8,646)	(4,108)
Total Income Taxes as Reported	$ (1,907)	$ 105,220	$ 73,662	$ 41,148	$ 9,675
Effective Income Tax Rate	N.M.	34.2%	29.8%	31.5%	22.4%

	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Year Ended December 31, 2003					
Net Income	$ 375,663	$ 53,891	$ 98,141	$ 217,669	$ 58,557
Cumulative Effect of Accounting Changes	(124,632)	-	(8,517)	(122)	(3,071)
Extraordinary Loss	-	-	-	-	177
Income Taxes	138,399	37,837	51,072	105,172	30,263
Pretax Income	$ 389,430	$ 91,728	$ 140,696	$ 322,719	$ 85,926
Income Tax on Pretax Income at Statutory Rate (35%)	$ 136,301	$ 32,105	$ 49,244	$ 112,952	$ 30,074
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	4,096	(467)	(390)	(957)	(214)
Investment Tax Credits (net)	(3,107)	(1,791)	(4,326)	(5,207)	(1,521)
State and Local Income Taxes	4,717	2,886	9,723	(10,434)	3,078
Other	(3,608)	5,104	(3,179)	8,818	(1,154)
Total Income Taxes as Reported	$ 138,399	$ 37,837	$ 51,072	$ 105,172	$ 30,263
Effective Income Tax Rate	35.5%	41.2%	36.3%	32.6%	35.2%

N.M. = Not Meaningful

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Year Ended December 31, 2002					
Net Income	$ 7,552	$ 205,492	$ 181,173	$ 73,992	$ 20,567
Income Taxes	(1,955)	110,926	111,003	44,837	10,862
Pretax Income	$ 5,597	$ 316,418	$ 292,176	$ 118,829	$ 31,429
Income Tax on Pretax Income at Statutory Rate (35%)	$ 1,959	$ 110,746	$ 102,262	$ 41,590	$ 11,000
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	286	3,082	2,899	21,812	2,057
Nuclear Fuel Disposal Costs	-	-	-	(3,087)	-
Allowance for Funds Used During Construction	(1,136)	-	-	(3,453)	-
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	(735)
Investment Tax Credits (net)	(3,361)	(4,637)	(3,270)	(7,740)	(1,240)
State and Local Income Taxes	335	6,469	11,387	124	1,058
Other	(412)	(4,734)	(2,275)	(4,409)	(1,278)
Total Income Taxes as Reported	$ (1,955)	$ 110,926	$ 111,003	$ 44,837	$ 10,862
Effective Income Tax Rate	N.M.	35.1%	38.0%	37.7%	34.6%

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2002					
Net Income	$ 220,023	$ 41,060	$ 82,992	$ 275,941	$ (13,677)
Income Taxes	131,591	22,383	35,468	142,166	(12,103)
Pretax Income	$ 351,614	$ 63,443	$ 118,460	$ 418,107	$ (25,780)
Income Tax on Pretax Income at Statutory Rate (35%)	$ 123,065	$ 22,205	$ 41,461	$ 146,337	$ (9,023)
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	4,227	(583)	(2,790)	(295)	(32)
Investment Tax Credits (net)	(3,177)	(1,791)	(4,524)	(5,207)	(1,271)
State and Local Income Taxes	18,051	2,639	3,987	2,202	(1,577)
Other	(10,575)	(87)	(2,666)	(871)	(200)
Total Income Taxes as Reported	$ 131,591	$ 22,383	$ 35,468	$ 142,166	$ (12,103)
Effective Income Tax Rate	37.4%	35.3%	29.9%	34.0%	46.9%

N.M. = Not Meaningful

The following tables show the elements of the net deferred tax liability and the significant temporary differences for each Registrant Subsidiary:

	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Year Ended December 31, 2004					
Deferred Tax Assets	$ 65,740	$ 238,784	$ 98,848	$ 650,596	$ 39,511
Deferred Tax Liabilities	(90,502)	(1,091,320)	(563,393)	(966,326)	(267,047)
Net Deferred Tax Liabilities	$ (24,762)	$ (852,536)	$ (464,545)	$ (315,730)	$ (227,536)
Property Related Temporary Differences	$ (58,895)	$ (680,324)	$ (385,426)	$ (71,771)	$ (169,452)
Amounts Due From Customers For Future Federal Income Taxes	6,266	(94,438)	(5,652)	(34,260)	(25,112)
Deferred State Income Taxes	(5,050)	(106,817)	(25,658)	(48,830)	(32,099)
Transition Regulatory Assets	-	(8,914)	(54,852)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	43,978	32,747	24,366	4,725
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	33,967	-	-	22,600	-
Accrued Nuclear Decommissioning Expense	-	-	-	(188,428)	-
Deferred Fuel and Purchased Power	-	20,245	(39)	(19)	-
Accrued Pensions	-	(8,306)	(12,528)	6,135	(768)
Provision for Refund	-	809	-	(73)	-
Nuclear Fuel	-	-	-	(15,485)	-
All Other (Net)	(1,050)	(18,769)	(13,137)	(9,965)	(4,830)
Net Deferred Tax Liabilities	$ (24,762)	$ (852,536)	$ (464,545)	$ (315,730)	$ (227,536)

	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Year Ended December 31, 2004					
Deferred Tax Assets	$ 165,891	$ 76,411	$ 70,039	$ 248,456	$ 33,063
Deferred Tax Liabilities	(1,109,356)	(460,501)	(469,795)	(1,495,567)	(171,528)
Net Deferred Tax Liabilities	$ (943,465)	$ (384,090)	$ (399,756)	$ (1,247,111)	$ (138,465)
Property Related Temporary Differences	$ (781,479)	$ (331,428)	$ (341,306)	$ (390,709)	$ (132,383)
Amounts Due From Customers For Future Federal Income Taxes	(55,121)	7,687	5,927	7,513	4,552
Deferred State Income Taxes	(78,060)	(59,598)	(44,074)	(42,693)	(7,705)
Transition Regulatory Assets	(79,480)	-	(153)	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,853)	-
Deferred Income Taxes on Other Comprehensive Loss	39,989	(40)	635	188	69
Deferred Fuel and Purchased Power	-	(126)	(10,274)	(1,738)	(8,554)
Accrued Pensions	(7,963)	(30,463)	(26,219)	(38,836)	(16,432)
Provision for Refund	-	67	1,915	51,838	11,513
Deferred Book Gain	-	-	-	71,749	-
Regulatory Assets	-	-	(581)	(580,736)	2,886
Securitized Transition Assets	-	-	-	(257,612)	-
All Other (Net)	18,649	29,811	14,374	3,854	7,589
Net Deferred Tax Liabilities	$ (943,465)	$ (384,090)	$ (399,756)	$ (1,247,111)	$ (138,465)

	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Year Ended December 31, 2003					
Deferred Tax Assets	$ 79,545	$ 237,873	$ 122,453	$ 695,037	$ 44,413
Deferred Tax Liabilities	(103,874)	(1,041,228)	(580,951)	(1,032,413)	(256,534)
Net Deferred Tax Liabilities	$ (24,329)	$ (803,355)	$ (458,498)	$ (337,376)	$ (212,121)
Property Related Temporary Differences	$ (62,271)	$ (623,126)	$ (357,980)	$ (74,501)	$ (151,404)
Amounts Due From Customers For Future Federal Income Taxes	6,949	(94,457)	(5,575)	(37,233)	(23,203)
Deferred State Income Taxes	(4,350)	(87,484)	(26,972)	(45,736)	(33,535)
Transition Regulatory Assets	-	(10,799)	(66,002)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	28,047	24,946	13,519	3,345
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	36,916	-	-	24,563	-
Accrued Nuclear Decommissioning Expense	-	-	-	(173,054)	-
Deferred Fuel and Purchased Power	-	24,047	(273)	(19)	496
Deferred Cook Plant Restart Costs	-	-	-	(20,064)	-
Accrued Pensions	-	(8,019)	(13,000)	(2,832)	(1,006)
Provision for Refund	-	809	-	(73)	-
Nuclear Fuel	-	-	-	(7,027)	-
All Other (Net)	(1,573)	(32,373)	(13,642)	(14,919)	(6,814)
Net Deferred Tax Liabilities	$ (24,329)	$ (803,355)	$ (458,498)	$ (337,376)	$ (212,121)

	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Year Ended December 31, 2003					
Deferred Tax Assets	$ 192,026	$ 164,801	$ 163,457	$ 298,648	$ 67,794
Deferred Tax Liabilities	(1,125,608)	(500,235)	(512,521)	(1,543,560)	(180,813)
Net Deferred Tax Liabilities	$ (933,582)	$ (335,434)	$ (349,064)	$ (1,244,912)	$ (113,019)
Property Related Temporary Differences	$ (721,118)	$ (297,809)	$ (321,082)	$ (698,554)	$ (118,876)
Amounts Due From Customers For Future Federal Income Taxes	(55,143)	8,728	8,259	8,330	5,402
Deferred State Income Taxes	(80,573)	(56,413)	(33,651)	(42,044)	(2,946)
Transition Regulatory Assets	(109,150)	-	-	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,470)	-
Nuclear Fuel	-	-	-	(7,240)	-
Deferred Income Taxes on Other Comprehensive Loss	26,280	23,607	23,644	33,316	14,387
Deferred Fuel and Purchased Power	12	(8,460)	(10,996)	(1,738)	(10,143)
Accrued Pensions	(9,222)	(16,088)	(12,922)	(20,054)	(9,961)
Provision for Refund	-	67	3,000	29,823	7,601
Regulatory Assets	-	-	-	(199,945)	4,577
Securitized Transition Assets	-	-	-	(281,260)	-
All Other (Net)	15,332	10,934	(5,316)	4,000	(3,060)
Net Deferred Tax Liabilities	$ (933,582)	$ (335,434)	$ (349,064)	$ (1,244,912)	$ (113,019)

The IRS and other taxing authorities routinely examine the Registrant Subsidiaries tax returns. Management believes that the Registrant Subsidiaries have filed tax returns with positions that may be challenged by these tax authorities. Theses positions relate to the timing and amount of income, deductions and the computation of the tax liability. Registrant Subsidiaries have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. Registrant Subsidiaries 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 the 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, Registrant Subsidiaries have total provisions for uncertain tax positions of approximately $23 million, excluding AEGCo. In addition, the Registrant Subsidiaries accrue 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.

Registrant Subsidiaries join in the filing of a consolidated federal income tax return with 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.

15. 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:

	AEGCo	APCo	CSPCo	I&M	KPCo
Year Ended December 31, 2004			(in thousands)		
Lease Payments on Operating Leases	$ 75,545	$ 6,832	$ 5,313	$ 111,344	$ 1,416
Amortization of Capital Leases	92	7,906	3,933	6,825	1,605
Interest on Capital Leases	7	1,260	705	1,403	258
Total Lease Rental Costs	$ 75,644	$ 15,998	$ 9,951	$ 119,572	$ 3,279

	OPCo	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2004			(in thousands)		
Lease Payments on Operating Leases	$ 14,390	$ 3,697	$ 4,877	$ 3,949	$ 1,458
Amortization of Capital Leases	8,232	520	3,543	437	216
Interest on Capital Leases	2,259	53	2,054	66	27
Total Lease Rental Costs	$ 24,881	$ 4,270	$ 10,474	$ 4,452	$ 1,701

	AEGCo	APCo	CSPCo	I&M	KPCo
Year Ended December 31, 2003			(in thousands)		
Lease Payments on Operating Leases	$ 76,322	$ 6,148	$ 5,277	$ 111,923	$ 1,258
Amortization of Capital Leases	269	9,217	4,898	7,370	1,951
Interest on Capital Leases	-	1,123	899	1,276	148
Total Lease Rental Costs	$ 76,591	$ 16,488	$ 11,074	$ 120,569	$ 3,357

	OPCo	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2003			(in thousands)		
Lease Payments on Operating Leases	$ 40,034	$ 4,883	$ 4,708	$ 6,360	$ 2,132
Amortization of Capital Leases	9,437	174	1,434	161	83
Interest on Capital Leases	2,472	17	899	16	9
Total Lease Rental Costs	$ 51,943	$ 5,074	$ 7,041	$ 6,537	$ 2,224

Year Ended December 31, 2002	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Lease Payments on Operating Leases	$ 76,143	$ 6,634	$ 5,209	$ 112,037	$ 1,597
Amortization of Capital Leases	238	9,729	6,010	8,319	2,171
Interest on Capital Leases	19	2,240	1,717	2,221	469
Total Lease Rental Costs	$ 76,400	$ 18,603	$ 12,936	$ 122,577	$ 4,237

Year Ended December 31, 2002	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Lease Payments on Operating Leases	$ 80,210	$ 4,403	$ 3,240	$ 7,184	$ 1,981
Amortization of Capital Leases	12,637	-	-	-	-
Interest on Capital Leases	4,501	-	-	-	-
Total Lease Rental Costs	$ 97,348	$ 4,403	$ 3,240	$ 7,184	$ 1,981

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

Year Ended December 31, 2004	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Property, Plant and Equipment Under Capital Leases:					
Production	$ 12,339	$ 1,759	$ 7,104	$ 22,917	$ 797
Distribution	-	-	-	14,589	-
Other	353	45,892	21,270	43,478	10,405
Total Property, Plant and Equipment	12,692	47,651	28,374	80,984	11,202
Accumulated Amortization	218	27,709	15,884	30,252	6,839
Net Property, Plant and Equipment Under Capital Leases	$ 12,474	$ 19,942	$ 12,490	$ 50,732	$ 4,363
Obligations Under Capital Leases:					
Noncurrent Liability	$ 12,264	$ 13,136	$ 8,660	$ 44,608	$ 2,802
Liability Due Within One Year	210	6,742	3,854	6,124	1,561
Total Obligations Under Capital Leases	$ 12,474	$ 19,878	$ 12,514	$ 50,732	$ 4,363

Year Ended December 31, 2004	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Property, Plant and Equipment Under Capital Leases:					
Production	$ 34,796	$ -	$ 14,269	$ -	$ -
Distribution	-	-	-	-	-
Other	46,131	1,813	53,620	1,364	780
Total Property, Plant and Equipment	80,927	1,813	67,889	1,364	780
Accumulated Amortization	41,187	529	33,343	484	246
Net Property, Plant and Equipment Under Capital Leases	$ 39,740	$ 1,284	$ 34,546	$ 880	$ 534
Obligations Under Capital Leases:					
Noncurrent Liability	$ 31,652	$ 747	$ 30,854	$ 468	$ 314
Liability Due Within One Year	9,081	537	3,692	412	220
Total Obligations Under Capital Leases	$ 40,733	$ 1,284	$ 34,546	$ 880	$ 534

Year Ended December 31, 2003	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Property, Plant and Equipment Under Capital Leases:					
Production	$ 865	$ 2,758	$ 7,104	$ 4,492	$ 1,138
Distribution	-	-	-	14,589	-
Other	-	55,640	25,345	52,536	11,562
Total Property, Plant and Equipment	865	58,398	32,449	71,617	12,700
Accumulated Amortization	596	33,036	16,828	33,774	7,408
Net Property, Plant and Equipment Under Capital Leases	$ 269	$ 25,362	$ 15,621	$ 37,843	$ 5,292
Obligations Under Capital Leases:					
Noncurrent Liability	$ 182	$ 16,134	$ 11,397	$ 31,315	$ 3,549
Liability Due Within One Year	87	9,218	4,221	6,528	1,743
Total Obligations Under Capital Leases	$ 269	$ 25,352	$ 15,618	$ 37,843	$ 5,292

Year Ended December 31, 2003	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Property, Plant and Equipment Under Capital Leases:					
Production	$ 21,099	$ -	$ -	$ -	$ -
Distribution	-	-	-	-	-
Other	53,752	1,176	52,695	1,204	556
Total Property, Plant and Equipment	74,851	1,176	52,695	1,204	556
Accumulated Amortization	40,565	166	31,153	160	83
Net Property, Plant and Equipment Under Capital Leases	$ 34,286	$ 1,010	$ 21,542	$ 1,044	$ 473
Obligations Under Capital Leases:					
Noncurrent Liability	$ 25,064	$ 558	$ 18,383	$ 636	$ 270
Liability Due Within One Year	9,624	452	3,159	407	203
Total Obligations Under Capital Leases	$ 34,688	$ 1,010	$ 21,542	$ 1,043	$ 473

Future minimum lease payments consisted of the following at December 31, 2004:

Capital Leases	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
2005	$ 990	$ 7,988	$ 4,468	$ 8,367	$ 1,854
2006	980	6,192	3,184	6,895	1,195
2007	972	3,512	2,178	4,733	962
2008	964	3,060	2,100	4,342	519
2009	962	1,053	1,131	6,734	184
Later Years	17,997	1,060	931	25,348	169
Total Future Minimum Lease Payments	22,865	22,865	13,992	56,419	4,883
Less Estimated Interest Element	10,391	2,987	1,478	5,687	520
Estimated Present Value of Future Minimum Lease Payments	$ 12,474	$ 19,878	$ 12,514	$ 50,732	$ 4,363

Capital Leases	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
2005	$ 9,795	$ 579	$ 6,160	$ 456	$ 242
2006	9,295	413	6,057	300	140
2007	7,093	211	5,892	120	59
2008	5,061	99	5,832	71	44
2009	3,392	44	5,445	18	41
Later Years	20,332	33	20,513	-	59
Total Future Minimum Lease Payments	54,968	1,379	49,899	965	585
Less Estimated Interest Element	14,235	95	15,353	85	51
Estimated Present Value of Future Minimum Lease Payments	$ 40,733	$ 1,284	$ 34,546	$ 880	$ 534

Noncancelable Operating Leases	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
2005	$ 73,955	$ 7,126	$ 5,670	$ 104,003	$ 1,475
2006	73,938	6,126	3,212	98,883	1,150
2007	73,934	4,554	2,720	96,330	982
2008	73,933	3,624	2,089	95,529	741
2009	73,932	2,982	1,755	94,630	595
Later Years	960,341	6,354	3,188	1,019,602	1,792
Total Future Minimum Lease Payments	$ 1,330,033	$ 30,766	$ 18,634	$ 1,508,977	$ 6,735

Noncancelable Operating Leases	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
2005	$ 16,220	$ 5,760	$ 6,793	$ 5,751	$ 2,200
2006	15,005	4,877	6,786	4,117	1,860
2007	14,448	4,409	7,979	3,456	1,497
2008	13,893	2,334	8,917	2,694	1,315
2009	13,410	2,139	8,176	2,377	1,440
Later Years	71,888	6,777	10,614	6,276	3,053
Total Future Minimum Lease Payments	$ 144,864	$ 26,296	$ 49,265	$ 24,671	$ 11,365

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 to 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.

16. FINANCING ACTIVITIES

Dividend Restrictions

Under PUHCA, Registrant 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 Investments within Other Property and Investments 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 Investments at 12/31/04 (a)	Amount in Notes Payable to Trust at 12/31/04 (b)	Amount in Other Investments 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 Investments within Other Property and Investments.
(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.

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the AEP System also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The AEP System Corporate Borrowing Program operates in accordance with the terms and conditions outlined by the SEC. AEP has authority from the SEC through March 31, 2007 for short-term borrowings sufficient to fund the Utility Money Pool and the Nonutility Money Pool as well as its own requirements in an amount not to exceed $7.2 billion. The Utility Money Pool participants' money pool activity and corresponding SEC authorized limits for the year ended December 31, 2004 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of December 31, 2004	SEC Authorized Short-Term Borrowing Limit
			(in thousands)			
AEGCo	$ 56,525	$ 932	$ 23,532	$ 731	$ (26,915)	$ 125,000
APCo	211,060	32,575	76,100	13,501	(211,060)	600,000
CSPCo	29,687	184,962	12,808	75,580	141,550	350,000
I&M	216,528	70,363	89,578	29,290	5,093	500,000
KPCo	44,749	41,501	13,580	15,282	16,127	200,000
OPCo	81,862	297,136	29,578	152,442	125,971	600,000
PSO	145,619	35,158	47,099	16,204	(55,002)	300,000
SWEPCo	71,252	107,966	38,073	64,386	39,106	350,000
TCC	109,696	427,414	62,494	120,312	(207)	600,000
TNC	16,136	110,430	6,704	41,500	51,504	250,000

Maximum, minimum and average interest rates for funds loaned to and borrowed from the Utility Money Pool during 2004 are summarized in the following table:

Company	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
			(in percentages)			
AEGCo	2.24	0.89	1.97	1.78	1.47	1.91
APCo	2.24	0.89	1.72	1.23	1.68	1.48
CSPCo	1.88	0.92	2.24	0.89	1.50	1.69
I&M	2.24	0.89	2.23	0.94	1.45	1.93
KPCo	1.92	0.91	2.24	0.89	1.59	1.61
OPCo	1.92	1.18	2.24	0.89	1.29	1.46
PSO	2.23	0.89	2.24	1.29	1.38	1.80
SWEPCo	1.92	0.89	2.24	0.91	1.37	1.67
TCC	2.23	0.91	2.24	0.89	1.40	1.47
TNC	1.50	0.91	2.24	0.89	1.09	1.56

As of December 31, 2004, AEP had credit facilities totaling $2.8 billion to support its commercial paper program. At December 31, 2004, AEP 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 15. This commercial paper does not reduce AEP's available liquidity. As of December 31, 2004, AEP's 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 AEP's short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poor's Rating Services reaffirmed AEP's A-2 short-term rating for commercial paper. On August 2, 2004, Moody's Investor Services placed AEP's ratings on positive outlook.

Interest expense related to the Utility Money Pool is included in Interest Charges in each of the Registrant Subsidiaries' Financial Statements. The Registrant Subsidiaries incurred interest expense for amounts borrowed from the Utility Money Pool as follows:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
AEGCo	$ 338	$ 289	$ 345
APCo	1,136	147	4,396
CSPCo	32	732	1,771
I&M	1,127	313	196
KPCo	65	897	1,638
OPCo	51	2,332	5,685
PSO	486	1,218	4,114
SWEPCo	217	787	3,118
TCC	177	617	7,773
TNC	8	449	3,242

Interest income related to the Utility Money Pool is included in Nonoperating Income in each of the Registrant Subsidiaries' Financial Statements. Interest income earned from amounts advanced to the Utility Money Pool by registrant were:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
AEGCo	$ 1	$ 8	$ 126
APCo	24	1,589	366
CSPCo	1,076	777	683
I&M	84	1,814	1,260
KPCo	177	-	2
OPCo	1,965	700	-
PSO	76	156	-
SWEPCo	649	662	105
TCC	1,445	589	-
TNC	587	164	-

Outstanding short-term debt for AEP Consolidated consisted of:

	Year Ended December 31,	
	2004	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. AEP has 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 into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP 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:

	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 Receivables	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:

	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.

Under the factoring arrangement, participating Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company's receivables and administrative costs. The costs of factoring customer accounts receivable are reported as an operating expense. The amount of factored accounts receivable and accrued unbilled revenues for each Registrant Subsidiary was as follows:

	December 31,	
	2004	2003
	(in millions)	
APCo	$ 58.7	$ 60.2
CSPCo	110.1	100.2
I&M	91.4	93.0
KPCo	34.4	30.4
OPCo	106.0	99.3
PSO	96.7	99.6
SWEPCo	72.0	64.4

The fees paid by the Registrant Subsidiaries to AEP Credit for factoring customer accounts receivable were:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
APCo	$ 3.9	$ 3.4	$ 4.8
CSPCo	10.2	9.8	15.8
I&M	6.5	6.1	7.4
KPCo	2.6	2.4	2.7
OPCo	7.7	8.7	11.4
PSO	8.9	5.8	7.2
SWEPCo	5.8	4.9	5.4
TCC	-	-	2.2
TNC	-	-	1.4

17. RELATED PARTY TRANSACTIONS

For other related party transactions, also see in Note 16 "Lines of Credit – AEP System" and "Sale of Receivables-AEP Credit."

AEP System Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

Power and Gas and risk management activities are conducted by the AEP Power Pool and profits/losses are shared among the parties under the System Integration Agreement. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition the risk management of electricity, and to a lesser extent gas contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which has been approved by the FERC. The CSW Operating Agreement requires the AEP West companies to maintain adequate annual planning reserve margins and requires the operating companies that have capacity in excess of the required margins to make such capacity available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are shared based on the amount of energy each AEP West company contributes that is sold to third parties. Upon sale of its generation assets, TCC will no longer supply generating capacity under the CSW Operating Agreement.

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

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any Registrant Subsidiary is primarily sold to customers (or in the case of the ERCOT area of Texas, REPs) by such Registrant Subsidiary at rates approved (other than in Ohio, Virginia and the ERCOT area of Texas) by the public utility commission in the jurisdiction of sale. In Ohio, Virginia and the ERCOT area of Texas, such rates are based on a statutory formula as those jurisdictions transition to the use of market rates for generation (see Note 6).

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the native load of any Registrant Subsidiary is sold in the wholesale market by AEPSC on behalf of the generating subsidiary. See Note 13 for a discussion of the marketing of such power.

AEP East and West Companies Sales and Purchases to the Pools

The following table shows the revenues derived from sales to the pools and direct sales to affiliates for years ended December 31, 2004, 2003 and 2002:

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
			(in thousands)			
2004						
Sales to East System Pool	$ 128,736	$ 60,409	$ 243,105	$ 36,032	$ 497,925	$ -
Direct Sales to East Affiliates	62,018	-	-	-	57,241	241,578
Direct Sales to West Affiliates	22,017	13,190	14,536	5,155	17,721	-
Other	3,792	6,516	3,533	403	8,628	-
Total Revenues	$ 216,563	$ 80,115	$ 261,174	$ 41,590	$ 581,515	$ 241,578

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
			(in thousands)			
2003						
Sales to East System Pool	$ 130,921	$ 59,113	$ 228,667	$ 32,827	$ 503,334	$ -
Sales to West System Pool	27	9	17	6	21	-
Direct Sales to East Affiliates	60,638	-	-	-	50,764	232,955
Direct Sales to West Affiliates	27,951	16,428	17,674	6,425	21,759	-
Other	3,256	8,819	2,845	550	8,400	-
Total Revenues	$ 222,793	$ 84,369	$ 249,203	$ 39,808	$ 584,278	$ 232,955

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
			(in thousands)			
2002						
Sales to East System Pool	$ 106,651	$ 42,986	$ 197,525	$ 22,369	$ 397,248	$ -
Sales to West System Pool	18,300	12,107	13,036	4,717	16,265	-
Direct Sales to East Affiliates	58,213	-	-	-	50,599	213,071
Direct Sales to West Affiliates	-	-	-	-	-	-
Other	3,313	2,109	3,577	878	1,090	-
Total Revenues	$ 186,477	$ 57,202	$ 214,138	$ 27,964	$ 465,202	$ 213,071

Related Party Revenues	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2004				
Sales to West System Pool	$ 103	$ 521	$ -	$ 159
Direct Sales to East Affiliates	2,652	1,878	188	78
Direct Sales to West Affiliates	3,203	63,141	3,027	71
Other	4,732	5,650	43,824	51,372
Total Revenues	$ 10,690	$ 71,190	$ 47,039	$ 51,680

Related Party Revenues	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2003				
Sales to West System Pool	$ 793	$ 600	$ 15,157	$ 651
Direct Sales to East Affiliates	1,159	706	677	6
Direct Sales to West Affiliates	17,855	64,802	23,248	1,929
Other	3,323	2,746	114,486	52,567
Total Revenues	$ 23,130	$ 68,854	$ 153,568	$ 55,153

Related Party Revenues	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2002				
Sales to West System Pool	$ 674	$ 1,334	$ 18,416	$ 1,280
Direct Sales to East Affiliates	611	270	366	(23)
Direct Sales to West Affiliates	6,047	75,674	956,751	228,404
Other	2,107	(4,949)	32,911	10,764
Total Revenues	$ 9,439	$ 72,329	$ 1,008,444	$ 240,425

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2004, 2003, and 2002:

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2004					
Purchases from East System Pool	$ 370,038	$ 346,463	$ 102,760	$ 68,072	$ 84,042
Direct Purchases from East Affiliates	-	-	169,103	72,475	4,334
Direct Purchases from West Affiliates	915	539	589	211	979
Total Purchases	$ 370,953	$ 347,002	$ 272,452	$ 140,758	$ 89,355

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2003					
Purchases from East System Pool	$ 348,899	$ 335,916	$ 109,826	$ 71,259	$ 88,962
Direct Purchases from East Affiliates	1,546	936	164,069	70,249	1,234
Direct Purchases from West Affiliates	765	471	505	182	625
Total Purchases	$ 351,210	$ 337,323	$ 274,400	$ 141,690	$ 90,821

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2002					
Purchases from East System Pool	$ 233,677	$ 309,999	$ 83,918	$ 68,846	$ 70,338
Purchases from West System Pool	337	219	237	86	297
Direct Purchases from East Affiliates	583	387	149,569	64,070	519
Total Purchases	$ 234,597	$ 310,605	$ 233,724	$ 133,002	$ 71,154

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2004				
Purchases from East System Pool	$ 66	$ 177	$ -	$ -
Purchases from West System Pool	49	191	-	568
Direct Purchases from East Affiliates	45,689	24,988	1,984	1,278
Direct Purchases from West Affiliates	58,197	3,698	4,156	3,365
Total Purchases	$ 104,001	$ 29,054	$ 6,140	$ 5,211

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2003				
Purchases from East System Pool	$ 639	$ -	$ -	$ -
Purchases from West System Pool	704	741	289	15,467
Direct Purchases from East Affiliates	46,384	28,376	10,238	4,677
Direct Purchases from West Affiliates	61,912	18,087	8,570	19,265
Other	-	710	-	-
Total Purchases	$ 109,639	$ 47,914	$ 19,097	$ 39,409

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2002				
Purchases from East System Pool	$ 343	$ -	$ -	$ -
Purchases from West System Pool	874	(456)	1,366	15,475
Direct Purchases from East Affiliates	29,029	17,242	8,236	2,669
Direct Purchases from West Affiliates	59,208	25,236	13,804	19,438
Total Purchases	$ 89,454	$ 42,022	$ 23,406	$ 37,582

The above summarized related party revenues and expenses are reported as consolidated and are presented as Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on the statements of operations of each AEP Power Pool member. Since all of the above pool members are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

AEP System Transmission Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

The following table shows the net charges (credits) allocated among the parties to the Transmission Agreement during the years ended December 31, 2004, 2003 and 2002:

	2004	2003	2002
		(in thousands)	
APCo	$ (500)	$ -	$ (13,400)
CSPCo	37,700	38,200	42,200
I&M	(40,800)	(39,800)	(36,100)
KPCo	(6,100)	(5,600)	(5,400)
OPCo	9,700	7,200	12,700

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the AEP West companies, including the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the AEP West companies have delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the AEP West companies of revenues collected for transmission and ancillary services provided under the OATT.

The following table shows the net charges (credits) allocated among parties to the TCA during the years ended December 31, 2004, 2003 and 2002:

	2004	2003	2002
		(in thousands)	
PSO	$ 8,100	$ 4,200	$ 4,200
SWEPCo	13,800	5,000	5,000
TCC	(12,200)	(3,600)	(3,600)
TNC	(9,700)	(5,600)	(5,600)

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

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

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

CSPCo coal purchases from AEP Coal, Inc.

As a result of management's decision to exit our non-core businesses, AEP Coal, Inc. (AEP Coal) was sold in March 2004. During 2004, AEP Coal sold approximately 330,000 tons of coal mined by AEP Coal to CSPCo to be delivered (at CSPCo's expense) to the Conesville Plant for a price of $26.15 per ton. In 2003, AEP Coal and CSPCo were parties to a 2003 coal purchase agreement, dated October 15, 2002. The agreement provided for the sale of up to 960,000 tons of coal mined by AEP Coal to be delivered (at CSPCo's expense) to the Conesville Plant for a price ranging from $23.15 per ton to $26.15 per ton plus quality adjustments. In 2002, AEP Coal and CSPCo were parties to a 2002 coal purchase agreement, dated February 1, 2002. The agreement provided for the sale of up to 785,000 tons of coal mined by AEP Coal to be delivered (at CSPCo's expense) to the Conesville Plant for a price ranging from $24.00 per ton to $27.00 per ton plus quality adjustments. During 2004, 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of $9.5 million, $23.9 million and $21 million, respectively.

AEP Coal and CSPCo were parties to a 1998 coal transloading agreement, dated June 12, 1998. Pursuant to the agreement, AEP Coal transferred coal from railcars into trucks at AEP Coal's Muskie Transloading Facility and delivered the coal via trucks to CSPCo's Conesville Preparation Plant or CSPCo's Power Plant for a rate of $1.25 per ton, $1.25 per ton and $1.03 per ton, in 2004, 2003 and 2002, respectively. During 2004, 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of $1.0 million, $3.4 million and $3.5 million, respectively.

Natural Gas Contracts with DETM

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Concurrently, in order to ensure that there would be no financial impact to the companies as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. There is no impact to the AEP consolidated financial statements. The following table represents Registrant Subsidiaries' liabilities at December 31, 2004 and 2003:

Company	2004	2003
	(in thousands)	
APCo	$ (23,736)	$ (32,287)
CSPCo	(13,654)	(18,185)
I&M	(15,266)	(19,932)
KPCo	(5,570)	(7,349)
OPCo	(19,065)	(24,055)
Total	$ (77,291)	$ (101,808)

Fuel Agreement between OCPo and National Power Cooperative, Inc

In conjunction with a 500 MW agreement between OPCo and National Power Cooperative, Inc (NPC), AEPES entered into a fuel management agreement with those two parties to manage and procure fuel needs for the gas plant, which is owned by NPC. The plant went into service in July 2002 and the AEP East companies purchase 100% of the available generating capacity from the plant through December 2005. The related purchases of gas managed by AEPES were as follows:

Company	Year Ended December 31, 2004	2003 (in thousands)	2002
APCo	$ 1,351	$ 1,546	$ 583
CSPCo	804	936	387
I&M	884	1,000	418
KPCo	315	363	150
OPCo	980	1,234	519
Total	$ 4,334	$ 5,079	$ 2,057

Unit Power Agreements

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

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement was renegotiated and extended from December 31, 2004 to December 7, 2022.

I&M Barging and Other Services

I&M provides barging and other transportation services to affiliates. I&M records revenues from barging services as nonoperating income. The affiliates record costs paid to I&M for barging services as fuel expense or operation expense. The amount of affiliated revenues and affiliated expenses were:

Company	Year Ended December 31, 2004	2003 (in millions)	2002
I&M – revenues	$ 38.2	$ 31.9	$ 34.3
AEGCo – expense	9.5	8.1	7.8
APCo – expense	13.0	12.3	12.8
KPCo – expense	0.1	0.1	-
OPCo – expense	4.9	4.3	7.9
MEMCo – expense (Nonutility subsidiary of AEP)	10.7	7.1	5.7
AEP Energy Services – expense (Nonutility subsidiary of AEP)	-	-	0.1

MEMCO services provided and received

AEP MEMCO LLC (MEMCO) provides services for barge towing and general and administrative expenses to I&M. The costs are recorded by I&M as nonoperating expenses. For the years ended December 31, 2004, 2003 and 2002, I&M recorded $12.6 million, $8.8 million and $2.6 million, respectively.

I&M provides services for barge towing and general and administrative expenses to MEMCO. The income is recorded by I&M as an offset to nonoperating expense. For the years ended December 31, 2004, 2003 and 2002, I&M recorded $10.7 million, $7.0 million and $5.0 million, respectively.

Gas Purchases from HPL

HPL purchases physical gas in the spot market, which in turn, is sold to certain operating companies at cost for their fuel requirements. The related HPL sales to TCC and TNC are as follows:

	Year Ended December 31,		
	2004 (a)	2003	2002
Company		(in thousands)	
TCC	$ 129,682	$ 195,527	$ 157,346
TNC	45,767	44,197	64,385

(a) In 2004, purchases from Oklaunion along with the HPL purchases described above comprise the total Fuel from Affiliates for Electric Generation as shown on the Registrant Subsidiaries' financial statements.

OPCo Indemnification Agreement with AEPR

OPCo has an indemnification agreement with AEPR whereby AEPR holds OPCo harmless from market exposure related to OPCo's Power Purchase and Sale Agreement dated November 15, 2000 with Dow Chemical Company. In 2004, AEPR paid OPCo $21.5 million, which is reported in OPCo's Nonoperating Income and Nonoperating Expenses on its Consolidated Statements of Income. See Note 7, "Power Generation Facility – Affecting OPCo" for further discussion.

Purchased Power from Ohio Valley Electric Corporation

The amounts of power purchased by the Registrant Subsidiaries from Ohio Valley Electric Corporation, which is 44.2% owned by the AEP and CSPCo, for the years ended December 31, 2004, 2003 and 2002 were:

	Year Ended December 31,		
	2004	2003	2002
Company		(in thousands)	
APCo	$ 62,101	$ 55,219	$ 53,386
CSPCo	16,724	15,259	14,885
I&M	27,474	25,659	23,282
OPCo	55,052	50,995	50,135

Sales of Property

The Registrant Subsidiaries had sales of electric property for the years ended December 31, 2004, 2003 and 2002 as shown in the following table.

	2004
	(in thousands)
APCo to OPCo	$ 2,992
I&M to APCo	1,630

	2003
	(in thousands)
AEGCo to OPCo	$ 105
APCo to OPCo	1,079
I&M to OPCo	1,492
OPCo to APCo	2,768
OPCo to I&M	1,096

	2002
	(in thousands)
OPCo to I&M	$ 4,768

AEPSC

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the PUHCA.

18. JOINTLY-OWNED ELECTRIC UTILITY PLANT

CSPCo, PSO, SWEPCo, TCC and TNC have generating units that are jointly-owned with affiliated and nonaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly owned facilities in the same proportion as its ownership interest. Each Registrant Subsidiary's proportionate share of the operating costs associated with such facilities is included in its statements of operations and the investments are reflected in its balance sheets under utility plant as follows:

		Company's Share December 31,			
		2004		2003	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
CSPCo		(in thousands)			
W.C. Beckjord Generating Station (Unit No. 6)	12.5%	$ 15,531	$ 139	$ 15,455	$ 127
Conesville Generating Station (Unit No. 4)	43.5	85,036	654	82,115	722
J.M. Stuart Generating Station	26.0	209,842	60,535	204,820	50,326
Wm. H. Zimmer Generating Station	25.4	741,043	7,976	707,281	31,249
Transmission	(a)	62,287	3,744	62,061	742
Total		$ 1,113,739	$ 73,048	$ 1,071,732	$ 83,166
PSO					
Oklaunion Generating Station (Unit No. 1)	15.6%	$ 85,834	$ 345	$ 85,064	$ 518
SWEPCo					
Dolet Hills Generating Station (Unit No. 1)	40.2%	$ 237,741	$ 2,559	$ 236,116	$ 2,304
Flint Creek Generating Station (Unit No. 1)	50.0	93,887	756	93,309	737
Pirkey Generating Station (Unit No. 1)	85.9	456,730	2,373	454,303	3,125
Total		$ 788,358	$ 5,688	$ 783,728	$ 6,166
TCC (b)					
Oklaunion Generating Station (Unit No. 1)	7.8%	$ 39,464	$ 271	$ 38,798	$ 252
South Texas Project Generation Station (Units No. 1 and 2)	25.2	2,386,961	2,144	2,386,579	934
Total		$ 2,426,425	$ 2,415	$ 2,425,377	$ 1,186
TNC					
Oklaunion Generating Station (Unit No. 1)	54.7%	$ 287,198	$ 1,418	$ 285,314	$ 1,351

(a) Varying percentages of ownership.
(b) Included in Assets Held for Sale – Texas Generation Plants on TCC's Consolidated Balance Sheets.

The accumulated depreciation with respect to each Registrant Subsidiary's share of jointly owned facilities is shown below:

Company	December 31, 2004	December 31, 2003
	(in thousands)	
CSPCo	$ 464,136	$ 435,249
PSO	52,679	50,968
SWEPCo	491,269	465,871
TCC (a)	991,410	991,665
TNC	110,763	103,642

(a) Included in Assets Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

The unaudited quarterly financial information for each Registrant Subsidiary follows:

Quarterly Periods Ended:	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
March 31, 2004					
Operating Revenues	$ 55,282	$ 526,457	$ 362,305	$ 412,186	$ 113,513
Operating Income	1,547	87,397	54,508	56,813	19,214
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	1,827	65,336	45,119	43,008	11,611
Net Income	1,827	65,336	45,119	43,008	11,611
June 30, 2004					
Operating Revenues	$ 56,348	$ 464,517	$ 358,126	$ 406,802	$ 109,142
Operating Income	1,373	46,082	44,629	42,995	11,605
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	1,506	21,826	30,755	27,030	4,068
Net Income	1,506	21,826	30,755	27,030	4,068
September 30, 2004					
Operating Revenues	$ 65,303	$ 491,385	$ 391,833	$ 443,660	$ 114,712
Operating Income	2,214	62,690	65,262	67,482	13,479
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	2,404	38,459	52,570	51,548	6,160
Net Income	2,404	38,459	52,570	51,548	6,160
December 31, 2004					
Operating Revenues	$ 64,855	$ 465,823	$ 321,317	$ 398,932	$ 113,246
Operating Income	1,770	47,841	19,847	28,598	11,023
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	2,105	27,494	11,814	11,636	4,066
Net Income (Loss)	2,105	27,494	11,814	11,636	4,066

Quarterly Periods Ended:	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
March 31, 2004					
Operating Revenues	$ 589,706	$ 207,456	$ 236,160	$ 287,123	$ 104,377
Operating Income	108,359	856	20,197	55,519	17,350
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	80,164	(9,003)	5,021	29,404	13,096
Net Income (Loss)	80,164	(9,003)	5,021	29,404	13,096
June 30, 2004					
Operating Revenues	$ 533,058	$ 231,623	$ 268,728	$ 269,868	$ 101,052
Operating Income	62,910	16,860	41,528	23,337	10,772
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	38,783	7,391	27,946	(341)	7,751
Net Income (Loss)	38,783	7,391	27,946	(341)	7,751
September 30, 2004					
Operating Revenues	$ 558,116	$ 356,631	$ 330,370	$ 354,609	$ 152,504
Operating Income	80,837	47,202	60,618	67,790	21,895
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	50,685	38,980	47,209	43,012	16,853
Net Income	50,685	38,980	47,209	43,012	16,853
December 31, 2004					
Operating Revenues	$ 555,516	$ 251,811	$ 252,088	$ 263,666	$ 134,212
Operating Income	60,266	10,158	20,835	49,373	11,229
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes (a)	40,484	174	9,281	222,581	9,959
Net Income	40,484	174	9,281	102,047	9,959

(a) See "Texas Restructuring" and "Net Stranded Generation Costs" sections of Note 6 for a discussion of net adjustments of stranded costs recorded in the fourth quarter of 2004.

Quarterly Periods Ended:	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
March 31, 2003					
Operating Revenues	$ 60,428	$ 536,228	$ 359,205	$ 418,598	$ 112,094
Operating Income	1,851	112,684	55,151	58,990	19,834
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	1,796	79,153	38,359	30,687	11,021
Net Income	1,796	156,410	65,642	27,527	9,887
June 30, 2003					
Operating Revenues	$ 59,568	$ 444,751	$ 333,071	$ 376,906	$ 95,464
Operating Income	1,514	49,056	43,417	19,229	10,964
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	1,768	14,636	29,331	(1,191)	4,095
Net Income (Loss)	1,768	14,636	29,331	(1,191)	4,095
September 30, 2003					
Operating Revenues	$ 59,008	$ 483,611	$ 397,655	$ 423,004	$ 103,693
Operating Income	1,809	67,134	71,193	56,242	13,097
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	2,021	45,715	62,825	37,116	6,501
Net Income	2,021	45,715	62,825	37,116	6,501
December 31, 2003					
Operating Revenues	$ 54,161	$ 492,768	$ 341,920	$ 377,088	$ 105,219
Operating Income	2,000	89,937	55,725	51,606	20,849
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	2,379	63,279	42,632	22,936	11,847
Net Income	2,379	63,279	42,632	22,936	11,847

Quarterly Periods Ended:	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
March 31, 2003					
Operating Revenues	$ 590,631	$ 242,662	$ 255,278	$ 428,358	$ 116,262
Operating Income	98,870	13,146	26,044	92,010	9,865
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	68,350	691	10,491	64,437	6,765
Net Income	192,982	691	19,008	64,559	9,836
June 30, 2003					
Operating Revenues	$ 539,386	$ 277,236	$ 281,306	$ 482,446	$ 136,806
Operating Income	79,831	28,715	35,588	96,603	23,243
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	56,277	17,927	20,590	63,587	17,922
Net Income	56,277	17,927	20,590	63,587	17,922
September 30, 2003					
Operating Revenues	$ 565,318	$ 358,575	$ 361,622	$ 485,129	$ 114,455
Operating Income	93,798	43,527	59,229	84,502	17,419
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	70,367	38,090	42,181	66,221	17,347
Net Income	70,367	38,090	42,181	66,221	17,347
December 31, 2003					
Operating Revenues	$ 549,318	$ 224,349	$ 248,636	$ 351,578	$ 98,423
Operating Income	87,168	7,475	29,275	48,425	17,500
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	56,037	(2,817)	16,362	23,302	13,629
Net Income (Loss)	56,037	(2,817)	16,362	23,302	13,452

For each of the Registrant Subsidiaries, (excluding TCC for 2004) there were no significant, nonrecurring events in the fourth quarter of 2004 or 2003.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, (iii) footnotes and (iv) the schedules of each individual registrant.

Source of Funding

Short-term funding for AEP's electric subsidiaries comes from AEP's commercial paper program and revolving credit facilities. Proceeds are loaned to the subsidiaries through intercompany notes. AEP and its subsidiaries also operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity for certain electric subsidiaries. The electric subsidiaries generally use short-term funding sources (the money pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leaseback, leasing arrangements and additional capital contributions from their parent company.

Dividend Restrictions

Under PUHCA, Registrant Subsidiaries can only pay dividends out of retained or current earnings.

Sale of Receivables Through 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. AEP does not have an ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP continues to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies' receivables, and accelerate 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 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 its West Virginia jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit.

Budgeted Construction Expenditures

Construction expenditures for Registrant Subsidiaries for 2005 are:

Company	Projected Construction Expenditures (in millions)
AEGCo	$ 19.9
APCo	696.7
CSPCo	193.9
I&M	322.8
KPCo	56.1
OPCo	765.6
PSO	126.2
SWEPCo	200.9
TCC	208.5
TNC	73.9

Significant Factors

Possible Divestitures

AEP's management is firmly committed to continually evaluating the need to reallocate resources to areas that effectively match investments with our business strategy, providing the greatest potential for financial returns and to disposing of investments that no longer meet these goals.

TCC made progress on its planned divestiture of its generation assets by (1) announcing in June 2004 and September 2004 that it had signed agreements to sell its 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 it had signed agreements to sell its 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 its remaining generation assets, including eight natural gas plants, one coal-fired plant and one hydro-electric plant for approximately $428 million, net of adjustments. TCC expects 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. TCC 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.

Texas Regulatory Activity – Affecting TCC

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 net 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 net adjustments are reflected as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax in TCC's Consolidated Statements of Income.

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 Stranded Cost Recovery in TCC's Consolidated Statements of Income. 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 TCC's 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, TCC determines that it is probable it cannot recover a portion of its recorded net true-up regulatory asset of $1.6 billion at December 31, 2004 and TCC is able to estimate the amount of such nonrecovery, TCC 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 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 – Affecting CSPCo and OPCo

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 $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 – Affecting PSO

PSO Fuel and Purchased Power

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West electric operating 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. PSO filed its brief on September 1, 2004. 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 PSO's revenues, results of operations, cash flows and financial condition.

FERC Order on Regional Through and Out Rates – Affecting AEP East Companies

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 were previously recovered from 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 East companies 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 AEP's 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 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 the AEP East companies 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

AEP maintains qualified, defined benefit pension plans (Qualified Plans or Pensions Plans), which cover a substantial majority of nonunion and certain union associates, 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, AEP has entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits. AEP also sponsors 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 AEP's 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, AEP 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. AEP also considered historical returns of the investment markets as well as its 10-year average return, for the period ended December 2004, of approximately 12%. AEP anticipates that the investment managers employed 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 AEP's targeted asset allocation and its expected investment returns for each investment category. AEP's 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%

AEP regularly reviews the actual asset allocation and periodically rebalances the investments to its 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. AEP believes 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. AEP will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them as necessary.

AEP bases its 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, AEP 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 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 AEP utilizes for determining future obligations was revised in 2004. Historically, AEP 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, AEP changed to a duration based method where a hypothetical portfolio of high quality corporate bonds was constructed with a duration similar to the duration of 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, AEP estimates that the pension cost for all pension plans will approximate $55 million, $54 million and $61 million in 2005, 2006 and 2007, respectively. AEP estimates 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 Combined Management's Discussion and Analysis of Registrant Subsidiaries.

The value of AEP's 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 AEP's 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 AEP's 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)

AEP made an additional discretionary contribution of $200 million in the fourth quarter of 2004 and intends to make additional discretionary contributions of $100 million per quarter in 2005 to meet the goal of fully funding all Qualified Plans by the end of 2005.

Certain pension plans AEP sponsors and maintains 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. AEP believes that the defined benefit pension plans it sponsors and maintains are in compliance with the applicable requirements of such laws.

Litigation

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation under "Environmental Matters."

Enron Bankruptcy

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

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 asserted its right to offset trading payables owed to various Enron entities against trading receivables due to several AEP 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.

The amounts expensed in prior years in connection with the Enron bankruptcy were 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 the offsetting of receivables and payables. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on results of operations, cash flows and 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. Management expects 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.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit against AEP and four of its subsidiaries including TCC and TNC, 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.

Coal Transportation Dispute

PSO, TCC, TNC and two nonaffiliated entities, as joint owners of a generating station, have disputed transportation costs billed for coal received between July 2000 and the present time. The joint plant has 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, PSO, as operator of the plant, recorded a provision for possible loss in December 2004 and a receivable from the other owners. The provision was deferred as a regulatory asset under PSO's fuel mechanism and affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

Other Litigation

AEP subsidiaries 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 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 management expects 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, AEP subsidiaries strive to go beyond compliance in an effort to be good environmental stewards. For example, AEP subsidiaries invest in research, through groups like the Electric Power Research Institute, to develop, implement and demonstrate new emission control technologies. AEP subsidiaries 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. AEP subsidiaries have a proven record of efficiently producing and delivering electricity while minimizing the impact on the environment. The AEP System has invested over $2 billion, from 1990 through 2004, to equip many of its facilities with pollution control technologies. The AEP System will continue to make investments to improve the air emissions from its fossil fuel generating stations as this is the most cost-effective generation source to meet its customers' electricity needs.

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

In August 2004, management released "An Assessment of AEP's Actions to Mitigate the Economic Impacts of Emissions Policies." The assessment evaluated the AEP System's operating emissions control technology, planned investment in additional control equipment and risks associated with an uncertain regulatory environment. It concluded that AEP's 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 to be undertaken to limit 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 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 subsidiaries operate) 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 the AEP System operates 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. The requirements apply to most of the AEP System's 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.

AEP subsidiaries 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.

AEP's 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 the AEP System's 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 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 the AEP System's 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. AEP supports enactment of a comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. Management believes this legislation would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. Management believes regulation or legislation will require the AEP System 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 AEP supports, 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 highly 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 AEP subsidiaries will invest in additional conventional pollution control technology on a major portion of their 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 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 management's 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
- Selected compliance alternatives.

As a result, management cannot estimate 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 the AEP subsidiaries' current investment base and operating cost structure. Management intends to seek recovery of these expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions). Management believes market prices should allow recovery of these expenditures 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

Management estimates that AEP subsidiaries 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, the AEP System has invested approximately $1.3 billion to comply with various NO_x requirements. Estimated future compliance costs, investment amounts estimated for 2005–2007 and amounts spent by subsidiaries are as follows:

	Future Estimated Compliance Investment	Investment Amount Estimated for 2005 – 2007	Amount Spent
		(in millions)	
AEGCo	$ -	$ -	$ 17
APCo	47	42	425
CSPCo	24	7	87
I&M	-	-	22
KPCo	48	-	181
OPCo	319	319	496
SWEPCo	14	11	25

Estimated Investments for SO_2 Compliance

The AEP System is complying with Title IV SO_2 requirements by installing scrubbers, other controls and fuel switching at certain generating units. AEP subsidiaries also use SO_2 allowances that were:

- 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, a diminishing SO_2 allowance bank, and increasing allowance prices in the market will require the installation of additional controls on certain generating units. AEP subsidiaries plan to install 3,500 MW of additional scrubbers to comply with our Title IV SO_2 obligations. In total, management estimates these additional capital costs to be approximately $1.2 billion with approximately $97 million invested during 2004 and the remainder will be expended during 2005-2007. The following table shows the estimated additional capital costs and amounts for 2005–2007 for additional scrubbers by subsidiary:

	Cost of Additional Scrubbers	Amount Estimated for 2005 – 2007
	(in millions)	
APCo	$ 442	$ 442
OPCo	727	714
SWEPCo	19	19

Estimated Investments to Comply with Future Reduction Requirements

The AEP System's 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. Management has 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. Management estimates that the subsidiaries will invest $1 billion of this amount through 2007.

	Estimated Compliance Investments	Amount Estimated for 2005 – 2007
	(in millions)	
APCo	$ 628	$ 469
CSPCo	236	133
I&M	61	8
KPCo	383	49
OPCo	364	319
SWEPCo	54	18

Management also estimates that the subsidiaries would incur increases in variable operation and maintenance expenses of $150 million for the periods by 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. Management 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 the AEP System operates within the three-year compliance schedule provided under the proposed MACT rule. These MACT compliance costs, which management is not able to estimate, would be incremental to other cost estimates that are discussed above.

Between 2010 and 2020, the AEP System expects 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. Management cannot estimate these additional costs because of the uncertainties associated with the final control requirements and the 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 AEP 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 the 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. AEP subsidiaries filed an answer to the complaint in January 2005.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. Management is 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 the AEP subsidiaries 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. The owners 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 generation plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and nonhazardous materials. AEP subsidiaries 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. As of year-end 2004, APCo, CSPCo, I&M and OPCo are each named by the Federal EPA as a Potentially Responsible Party (PRP) for one site. There are six additional sites for which APCo, CSPCo, I&M, KPCo, OPCo and SWEPCo have received information requests which could lead to PRP designation. OPCo, SWEPCo and TCC have also been named potentially liable at four 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 AEP subsidiaries have been named a PRP or defendant, 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 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, present estimates do not anticipate material cleanup costs for identified sites for which AEP subsidiaries have been declared PRPs. If significant cleanup costs are attributed to any AEP subsidiary in the future under Superfund, its results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in its 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 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.

AEP has 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, AEP has been a leader in pursuing voluntary actions to control greenhouse gas emissions. AEP expanded its commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program.

AEP subsidiaries made a voluntary commitment to reduce or offset 18 million tons of CO_2 emissions during 2003-2006 as adjusted to reflect any changes in 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. I&M 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, the 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, 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 AEP System 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. Management has not independently confirmed the accuracy of the Federal EPA's estimate. The rule has provisions to limit compliance costs. Management may propose less costly site-specific performance criteria if compliance cost estimates are significantly greater than the Federal EPA's estimates or greater than the environmental benefits. The rule also allows Management 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 APCo) and environmental groups appealed certain aspects of the rule. We cannot predict the outcome of the appeals. The following table shows the investment amount per subsidiary.

	Estimated Compliance Investments (in millions)
APCo	$ 21
CSPCo	19
I&M	118
OPCo	31

Other Environmental Concerns

Management performs 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, the AEP subsidiaries are managing other environmental concerns which are not believed to be material or potentially material at this time. If they become significant or if any new matters arise that 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 the Registrant Subsidiaries' 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 – The consolidated financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (I&M, KPCo, PSO and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo) 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 recognized for the economic effects of regulation by matching the timing of expense recognition with the recovery of such expense in regulated revenues. Likewise, income is matched with the passage to customers through regulated revenues in the same accounting period.

Regulatory liabilities are also recorded 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, they are recorded as assets on the balance sheet. Regulatory assets are tested 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, that regulatory asset is written-off 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 the results of operations. Refer to Note 5 of the Notes to Financial Statements of Registrant Subsidiaries for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required – Revenues are recognized and recorded 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 for the years ended December 31 were as follows:

	2004	2003	2002
		(in thousands)	
TCC	$ (1,579)	$ 4,636	$ (19,023)
TNC	(1,160)	1,834	(1,775)
APCo	18,206	1,876	3,890
CSPCo	283	(5,881)	6,917
I&M	(2,942)	10,722	9,329
KPCo	3,833	(448)	708
OPCo	(2,793)	(18,502)	(346)
PSO	2,789	984	4,008
SWEPCo	1,814	(6,996)	3,637

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%.

Revenue Recognition – Accounting for Derivative Instruments

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 – APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC 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, the fair value is estimated 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.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC 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.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC 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.

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 the applied valuation techniques. In cases of impairment as described in Note 10, the best estimate of fair value was made using valuation methods based on the most current information at that time. Certain Registrant Subsidiaries 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 – APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for 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 Financial Statements of Registrant Subsidiaries for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of pension and postretirement obligations, costs and liabilities is dependent on a variety of assumptions used by actuaries and APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. 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

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC 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 AEP subsidiaries' 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 the AEP System's facilities and the terms of power contracts into which AEP enters. In addition, AEP subsidiaries have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish results of operations and may impact cash flows and financial condition.