STP Nuclear Operating Company
South Texas Project Electric Generating Station P.O. Box 289 Wadsworth, Texas 77483

October 4, 2001
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STI No.: 31350986
File No.: G20
10CFR50.71(b)

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

South Texas Project
Units 1 and 2
Docket Nos.: STN 50-498; STN 50-499
Annual Financial Reports

Pursuant to the requirements of 10CFR50.71(b), STP Nuclear Operating Company acting on behalf of itself and for American Electric Power/Central Power & Light Company, the City of Austin, Texas, the City Public Service Board of San Antonio, and Reliant Energy, Inc. submits the attached current annual financial data for the South Texas Project Electric Generating Station.

Should you have any questions, comments, or require additional information please contact me at (361) 972-8562 or gmwilson@stpegs.com.

Gerald M. Wilson

G. M. Wilson
Supervisor,
Corporate Insurance

KMW

Attachments:

a)	American Electric Power	Annual Report
b)	American Electric Power	Form 10-K
c)	City of Austin	Annual Report
d)	City Public Service (San Antonio)	Annual Report
e)	Reliant Energy	Annual Report
f)	Reliant Energy	Form 10-K
g)	STP Nuclear Operating Company	Financial Statement

M004

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Appendix A to the
Proxy Statement

American Electric Power

2000 Annual Report

Audited Financial Statements and Management's Discussion and Analysis

AMERICAN ELECTRIC POWER
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CONTENTS

GLOSSARY OF TERMS

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

Term	Meaning
2004 True-up Proceeding	A filing to be made after January 10, 2004 under the Texas Legislation to finalize the amount of stranded costs and the recovery of such costs.
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned subsidiaries consolidated.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated and unaffiliated domestic electric utility companies.
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	AEP System Power Pool. Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale system sales of the member companies.
AFUDC	Allowance for funds used during construction, a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant.
Alliance RTO	Alliance Regional Transmission Organization, an ISO formed by AEP and four unaffiliated utilities.
Amos Plant	John E. Amos Plant, a 2,900 MW generation station jointly owned and operated by APCo and OPCo.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Arkansas Commission	Arkansas Public Service Commission.
Buckeye	Buckeye Power, Inc., an unaffiliated corporation.
CLECO	Central Louisiana Electric Company, Inc., an unaffiliated corporation.
COLI	Corporate owned life insurance program.
Cook Plant	The Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CPL	Central Power and Light Company, an AEP electric utility subsidiary.

CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP.
CSW Energy.	CSW Energy, Inc., an AEP subsidiary which invests in energy projects and builds power plants.
CSW International	CSW International, Inc., an AEP subsidiary which invests in energy projects and entities outside the United States.
D.C. Circuit Court	The United States Court of Appeals for the District of Columbia Circuit.
DHMV	Dolet Hills Mining Venture.
DOE	United States Department of Energy.
ECOM	Excess Cost Over Market.
ENEC	Expanded Net Energy Costs.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	The Electric Reliability Council of Texas.
EWGs	Exempt Wholesale Generators.
FASB	Financial Accounting Standards Board
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FMB	First Mortgage Bond.
FUCOs	Foreign Utility Companies.
GAAP	Generally Accepted Accounting Principles.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPC	Installment Purchase Contract.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
ISO	Independent system operator.
Joint Stipulation	Joint Stipulation and Agreement for Settlement of APCo's WV rate proceeding.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas.
Michigan Legislation	The Customer Choice and Electricity Reliability Act, a Michigan law which provides for customer choice of electricity supplier.
Midwest ISO	An independent operator of transmission assets in the Midwest.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.

Money Pool	AEP System's Money Pool.
MPSC	Michigan Public Service Commission.
MTN	Medium Term Notes.
MW	Megawatt.
MWH	Megawatthour.
NEIL	Nuclear Electric Insurance Limited.
NOx	Nitrogen oxide.
NOx Rule	A final rules issued by Federal EPA which requires NOx reductions in 22 eastern states including 7 of the states in which AEP operates.
NP	Notes Payable.
NRC	Nuclear Regulatory Commission.
Ohio Act	The Ohio Electric Restructuring Act of 1999.
Ohio EPA	Ohio Environmental Protection Agency.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo own a 44.2% equity interest.
PCBs	Polychlorinated Biphenyls.
PJM	Pennsylvania - New Jersey - Maryland regional transmission organization.
PRP	Potentially Responsible Party.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	The Public Utilities Commission of Ohio.
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.
RCRA	Resource Conservation and Recovery Act of 1976, as amended.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
SEC	Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation.
SFAS 101	Statement of Financial Accounting Standards No. 101, Accounting for the Discontinuance of Application of Statement 71.

SFAS 121	Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of.
SFAS 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.
SNF	Spent Nuclear Fuel.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by Central Power and Light Company an AEP electric utility subsidiary .
STPNOC	STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners including CPL.
Superfund	The Comprehensive Environmental, Response, Compensation and Liability Act.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Texas Appeals Court	The Third District of Texas Court of Appeals.
Texas Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
Travis District Court	State District Court of Travis County, Texas.
TVA	Tennessee Valley Authority.
U.K.	The United Kingdom.
UN	Unsecured Note.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WV	West Virginia.
WVPSC	Public Service Commission of West Virginia.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WTU	West Texas Utilities Company, an AEP electric utility subsidiary.
Yorkshire	Yorkshire Electricity Group plc, a U.K. regional electricity company owned jointly by AEP and New Century Energies.
Zimmer Plant	William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by Columbus Southern Power Company, an AEP subsidiary.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

SELECTED CONSOLIDATED FINANCIAL DATA

Year Ended December 31,	2000	1999	1998	1997	1996
INCOME STATEMENTS DATA (in millions):					
Total Revenues	$13,694	$12,407	$11,840	$11,163	$11,017
Operating Income	2,026	2,325	2,280	2,198	2,368
Income From Continuing Operations	302	986	975	949	871
Discontinued Operations	—	—	—	—	132
Extraordinary Loss	(35)	(14)	—	(285)	—
Net Income	267	972	975	664	1,003

December 31,	2000	1999	1998	1997	1996
BALANCE SHEETS DATA (in millions):					
Property, Plant and Equipment	$38,088	$36,938	$35,655	$33,496	$32,443
Accumulated Depreciation and Amortization	15,695	15,073	14,136	13,229	12,494
Net Property, Plant and Equipment	$22,393	$21,865	$21,519	$20,267	$19,949
Total Assets	$54,548	$35,719	$33,418	$30,092	$29,228
Common Shareholders' Equity	8,054	8,673	8,452	8,220	8,334
Cumulative Preferred Stocks of Subsidiaries:					
Not Subject to Mandatory Redemption	61	63	222	223	382
Subject to Mandatory Redemption*	100	119	128	154	543
Trust Preferred Securities	334	335	335	335	-
Long-term Debt*	10,754	11,524	11,113	9,354	9,112
Obligations Under Capital Leases*	614	610	539	549	422
*Including portion due within one year					

Year Ended December 31,	2000	1999	1998	1997	1996
COMMON STOCK DATA:					
Earnings per Common Share:					
Continuing Operations	$0.94	$3.07	$3.06	$2.99	$2.79
Discontinued Operations	—	—	—	—	0.42
Extraordinary Loss	(.11)	(.04)	—	(0.90)	—
Net Income	$0.83	$3.03	$3.06	$2.09	$3.21
Average Number of Shares Outstanding (in millions)	322	321	318	316	312
Market Price Range: High	$48-15/16	$48-3/16	$53-5/16	$52	$44-3/4
Low	25-15/16	30-9/16	42-1/16	39-1/8	38-5/8
Year-end Market Price	46-1/2	32-1/8	47-1/16	51-5/8	41-1/8
Cash Dividends on Common*	$2.40	$2.40	$2.40	$2.40	$2.40
Dividend Payout Ratio*	289.2%	79.2%	78.4%	114.8%	74.5%

Book Value per Share	$25.01	$26.96	$26.46	$25.91	$26.45

The consolidated financial statements give retroactive effect to AEP's merger with CSW, which was accounted for as a pooling of interests, as if AEP and CSW had always been combined.

* Based on AEP historical dividend rate.

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

This discussion includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions, and involve a number of risks and uncertainties. Among the factors both foreign and domestic that could cause actual results to differ materially from forward looking statements are: electric load and customer growth; abnormal weather conditions; available sources of and prices for coal and gas; availability of generating capacity; the impact of the merger with CSW including actual merger savings being less than the related rate reductions; risks related to energy trading and construction under contract; the speed and degree to which competition is introduced to our power generation business; the structure and timing of a competitive market for electricity and its impact on prices; the ability to recover net regulatory assets, other stranded costs and implementation costs in connection with deregulation of generation in certain states; new legislation and government regulations; the ability to successfully control costs; the success of new business ventures; international developments affecting our foreign investments; the economic climate and growth in our service and trading territories both domestic and foreign; the ability of the Company to successfully challenge new environmental regulations and to successfully litigate claims that the Company violated the Clean Air Act; successful resolution of litigation regarding municipal franchise fees in Texas; inflationary trends; changes in electricity and gas market prices; interest rates; foreign exchange rates, and other risks and unforeseen events.

American Electric Power Company, Inc. (AEP) is one of the largest investor owned electric public utility holding companies in the U.S. serving over 4.8 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) and selling bulk power at wholesale both within and beyond its domestic retail service area. AEP has 38,000 megawatts of generation and over 38,000 miles of transmission lines and 186,000 miles of distribution lines in the U.S. Subsidiaries own 1,250 megawatts as independent power producers in Colorado, Florida and Texas. In recent years AEP has expanded its domestic operations to include gas marketing, processing, storage and transportation operations, electric, gas and coal trading operations and telecommunication services and invested in and acquired foreign distribution operations in the U.K., Australia and Brazil and electricity generating facilities in China and Mexico. Subsidiaries also provide power engineering, generation and transmission plant maintenance and construction, and energy management services world-wide. AEP is one of the largest traders of electricity and gas in the U.S. In 2000 we established an energy trading operation in Europe.

Presently AEP is in the process of restructuring its assets and operations to separate the regulated operations from the non-regulated operations and to functionally and, where permitted by law, structurally unbundle its domestic vertically integrated electric utility business into separate generation, transmission and distribution businesses. The purpose of this restructuring is to focus our management and technical expertise to maximize the potential for growth of both non-regulated and regulated operations, to evaluate the performance of these separate and different businesses and to meet the separation requirements of federal and state restructuring legislation and codes of conduct. Five of AEP's 11 states (Arkansas, Ohio, Texas, Virginia, and West Virginia) are in various stages of transitioning to deregulation of generation and to customer choice and market-based pricing from monopoly and regulator set rates for the retail sale of electricity. When the transition is implemented in those states, transmission will be regulated by the Federal Energy Regulatory Commission and distribution services will continue to be cost-based rate regulated by the states. Although we are actively supporting the transition to competition, there is little progress in the remaining six states. Therefore, in the near term, our retail electric business in Indiana, Kentucky, Louisiana, Michigan, Oklahoma and Tennessee will continue to be operated as an integrated public utility subject to state regulation. The foreign energy delivery investments and operations are not cost-based rate regulated but they are generally subject to different forms of price controls, such as capped prices. As such these foreign investments and operations will be included in our unbundled regulated business.

On November 1, 2000, AEP filed a restructuring plan under PUHCA with the SEC seeking approval to form two wholly owned holding company subsidiaries of AEP to separately own AEP's regulated and non-regulated subsidiaries and to structurally separate into separate legal entities along functional lines (i.e. generation, transmission and distribution) six of the electric utility operating companies (APCo, CPL, CSPCo, OPCo, SWEPCo and WTU). These six operating companies do business in the states that are implementing restructuring (Arkansas, Ohio, Texas, Virginia and West Virginia). The remaining domestic electric operating companies will be functionally unbundled for internal management and internal reporting purposes and for financial segment reporting but will not be structurally unbundled into separate companies since state law and/or regulation prohibits such action. One holding company will hold the unbundled non-regulated electric generation subsidiaries and the non-regulated domestic and foreign subsidiaries including the European trading company and the foreign generating companies, while the other holding company will hold the bundled domestic regulated electric utility companies and the foreign distribution companies. The restructuring will facilitate management's strategy to grow the deregulated wholesale electricity supply and electric and gas trading business and to evaluate the other business operations to explore ways to improve their results of operations and to continuously evaluate and where necessary reshape our business to grow earnings and improve shareholder value. The legal transfer of assets and structural separation plans will also require FERC, certain state and other regulatory approvals.

2000 was a year of accomplishment for AEP that positions the Company for earnings growth. In 2000 we completed the merger of AEP and CSW, greatly increasing the scope and size of AEP; achieved the targeted merger savings; returned the two unit 2,110 MW Cook Plant to service after an extended outage; reached a settlement on a restructuring plan in Ohio that will allow our electric generating and supply business in Ohio to transition over five years to market pricing and recover its stranded cost, including generation-related regulatory assets; continued to grow our domestic electricity and gas trading businesses to become one of the largest electricity and gas traders; established and grew an energy trading operation in Europe; added to our gas assets and operations with the announcement in the first quarter of 2001 of the planned acquisition of Houston Pipe Line Company; restructured our incentive compensation plans to more closely align them with the creation of shareholder value; reduced our power plant operation and maintenance costs while increasing plant availability; established AEP Pro Serv, Inc. to market AEP's expertise in power engineering, environmental engineering and generating plant maintenance services worldwide; closed contracts to design, build, operate and market the output of new power plants for Dow Chemical, Buckeye Power and Columbia Energy; and initiated a re-design of our existing PeopleSoft financial software as part of an enterprise-wide application to fully integrate our financial, work management and supply chain software and to provide data on a business unit basis consistent with our corporate separation initiative.

Although 2000 was a year marked by significant accomplishments that position AEP for future earnings growth, it resulted in a reduction in earnings and earnings per share due mainly to non-recurring items, such as: a loss incurred from a court decision disallowing tax deductions for interest related to AEP's COLI program; the write-off of non-recoverable merger costs; the expensing of Cook nuclear restart costs in contrast to 1999 when a significant portion of the restart costs were deferred with regulatory approval; the write-off of certain extraordinary costs that were stranded and liabilities incurred in connection with the restructuring of the regulation of the electric utility business in Ohio, Virginia, and West Virginia to transition that portion of AEP's domestic electricity supply business from cost-based rate regulation to customer choice and market pricing; the recognition of losses associated with a CSW investment in Chile which was sold in the fourth quarter; an impairment writedown of AEP's investment in Yorkshire to reflect a pending sale of the investment in 2001; and write-offs of unrecoverable contract costs and goodwill on certain of CSW's non-regulated businesses acquired in the merger.

Earnings in 2001 are expected to improve significantly with the return of Cook Plant's 2,110 MW of generating capacity due to the completion of restart efforts and the cessation of significant restart costs at Cook and the growth of our wholesale marketing and trading business.

Our focus for 2001 will be on completing our corporate separation plan to separate our regulated and non-regulated businesses. We believe that a successful implementation of this plan will support our business objective of unlocking shareholder value by providing managers with a simpler structure through which business unit performance can be more easily anticipated and monitored thereby focusing management attention; permitting more efficient financing; and meeting the regulatory codes of conduct required as part of industry restructuring.

Although management expects that the future outlook for results of operations is excellent there are contingencies, challenges and obstacles to overcome and manage, such as new more stringent Federal EPA environmental requirements and recent complaints and related litigation, further delays in transition to competition supported in part by concerns that California's energy crisis could happen in our service territory, the recovery of generation-related regulatory assets and other stranded costs in Texas and any additional state jurisdictions that we can successfully promote the adoption of customer choice and a transition to market pricing from regulated rate setting, franchise fee litigation in Texas, litigation concerning AEP's financial disclosures regarding the extended Cook Plant safety outage and timing of the successful completion of restart efforts, the amortization of transition regulatory assets from the introduction of competition to our previously regulated domestic generation business and the amortization of deferred costs from the successful effort to restart Cook Plant and to merge AEP and CSW and the outcome of litigation to recover $90 million of duplicate tax expense from May 2001 to April 2002 resulting from restructuring in Ohio. These challenges, contingencies and obstacles, which are discussed in detail in the Notes to Consolidated Financial Statements and below in this Management Discussion and Analysis of Results of Operations and Financial Condition, are receiving management's full attention and we intend to work diligently to resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our shareholders.

RESULTS OF OPERATIONS

Net Income

Although revenues increased by $1.3 billion net income declined to $267 million or $0.83 per share in 2000 from $972 million or $3.03 per share in 1999. The decrease was primarily due to Cook Nuclear Plant restart costs, a disallowance of tax deductions for corporate owned life insurance (COLI), expensing of costs related to AEP's recently completed merger with CSW, write offs related to non-regulated subsidiaries and an extraordinary loss from the discontinuance of regulatory accounting for generation in certain states. In 1999 net income was virtually unchanged as increased expenses to prepare the Cook Nuclear Plant for restart, net of related deferrals, were offset by a gain from a sale of a 50% interest in a cogeneration project.

Revenues Increase

AEP's revenues include a significant number of transactions from the trading of electricity and gas. Revenues from trading of electricity are recorded net of purchases as domestic electric utility wholesale sales for transactions in AEP's traditional marketing area (up to two transmission systems from the AEP service territory) and as revenues from worldwide electric and gas operations for transactions beyond two transmission systems from AEP. Revenues from gas trading are recorded net of purchases and reported in revenues from worldwide electric and gas operations. Trading transactions involve the purchase and sale of substantial amounts of electricity and gas.

The level of electricity trading transactions tends to fluctuate due to the highly competitive nature of the short-term (spot) energy market and other factors, such as affiliated and unaffiliated generating plant availability, weather conditions and the economy. The FERC rules, which introduced a greater degree of competition into the wholesale energy market, have had a major effect on the volume of electricity trading as most electricity is traded in the short-term market.

AEP's total revenues increased 10% in 2000 and 5% in 1999. The table below shows the changes in the components of revenues from domestic electric utility operations and worldwide electric and gas operations. While worldwide electric and gas operations revenues increased 12% in 2000, most of the increase in total revenues was caused by the increased revenues from domestic electric utility operations.

	Increase (Decrease) From Previous Year			
(Dollars in Millions)	2000		1999	
	Amount	%	Amount	%
Domestic Electric				
Utility Operations:				
Retail:				
Residential	$230		$18	
Commercial	163		56	
Industrial	(71)		11	
Other	25		7	
	347	4.2	92	1.1
Wholesale	672	59.9	(145)	(11.5)
Other	(30)	(6.8)	57	15.3
Total	989	10.1	4	—
Worldwide Electric and Gas Operations	298	11.6	563	28.1
Total	$1,287	10.4	$ 567	4.8

The increase in total revenues from domestic electric utility operations in 2000 was primarily due to a 38% increase in wholesale sales volume and increased retail fuel revenues as a result of higher gas prices used to generate electricity. The reduction in industrial revenues in 2000 is attributable to the expiration of a long-term contract on December 31, 1999. The significant increase in wholesale sales volume, which accounted for a 60% increase in wholesale revenues, resulted from efforts to grow AEP's energy marketing and trading operations, favorable market conditions, and the availability of additional generation due to the return to service of one of the Cook Plant nuclear units in June 2000 and improved generating unit availability due mainly to improved outage management. The second Cook Plant unit which returned to service in December 2000 did not have a significant impact on revenues.

In 1999 revenues from domestic electric utility operations were unchanged. A 1% gain in retail revenues was more than offset by a 12% decline in wholesale revenues. The 12% decline in wholesale revenues in 1999 was predominantly due to a decrease in wholesale energy sales and a reduction in net revenues from power trading due to a decline in margins. The decrease in wholesale sales reflects the expiration in July 1998 of a power contract which supplied power to several municipal customers and the decision by another wholesale customer who buys energy under a unit power agreement not to take energy from AEP during an outage of that unit. The decline in wholesale margins in 1999 reflects the moderation of weather and the effected capacity shortages experienced in the summer of 1998.

Revenues from worldwide electric and gas operations increased 12% in 2000 due to increased natural gas and gas liquid product prices. Volumes of natural gas remained consistent with the prior year, however, prices increased significantly.

In 1999 revenues derived from worldwide electric and gas operations increased 28%. This increase is primarily due to the acquisitions in December 1998, of CitiPower in Australia and of LIG, and the commercial operation of a two-unit 250 MW coal-fired generating plant in China.

Operating Expenses Increase

Changes in the components of operating expenses were as follows:

	Increase (Decrease) From Previous Year			
(Dollars in Millions)	2000		1999	
	Amount	%	Amount	%
Fuel and Purchased Power	$679	19.7	$(6)	(0.2)
Maintenance and Other Operation	342	12.8	79	3.0
Non-recoverable Merger Costs	203	—	—	—
Depreciation and Amortization	51	5.0	22	2.2
Taxes Other Than Income Taxes	7	1.1	5	0.8
Worldwide Electric and Gas Operations	304	13.3	422	22.7
Total	$1,586	15.7	$522	5.5

Fuel and purchased power expense increased 20% in 2000 due to a significant increase in the cost of natural gas used for generation. Natural gas usage for generation declined 5% while the cost of natural gas consumed rose 60%. Net income was not impacted by this significant cost increase due to the operation of fuel recovery mechanisms. These fuel recovery mechanisms generally provide for the deferral of fuel costs above the amounts included in rates or the accrual of revenues for fuel costs not yet recovered. Upon regulatory commission review and approval of the unrecovered fuel costs, the accrued or deferred amounts are billed to customers.

The increase in maintenance and other operation expense in 2000 was mainly due to increased expenditures to prepare the Cook Plant nuclear units for restart following an extended NRC monitored outage and increased usage of and prices for emissions allowances. The increase in Cook Plant restart costs resulted from the effect of deferring restart costs in 1999 and an increase in the restart expenditure level. The Cook Plant began an extended outage in September 1997 when both nuclear generating units were shut down because of questions regarding the operability of certain safety systems. In 1999 a portion of incremental restart expenses were deferred in accordance with IURC and MPSC settlement agreements which resolved all jurisdictional rate-related issues related to the Cook Plant's extended outage. Unit 2 returned to service in June and achieved full power operation on July 5, 2000 and Unit 1 returned to service in December and achieved full power operation on January 3, 2001. The increase in emission allowance usage and prices resulted from the stricter air quality standards of Phase II of the 1990 Clean Air Act Amendments, which became effective on January 1, 2000. The increase in maintenance and other operation expense in 1999 was primarily due to a NRC required 10-year inspection of STP Units 1 and 2 and increased expenditures to prepare the Cook Plant nuclear units for restart. Although a portion of Cook Plant restart costs were deferred in 1999 pursuant to regulatory orders, net expenditures charged to expense increased over 1998.

With the consummation of the merger with CSW, certain deferred merger costs were expensed. The merger costs charged to expense included transaction and transition costs not allocable to and recoverable from ratepayers under regulatory commission approved settlement agreements to share net merger savings.

Worldwide electric and gas operations expense in 2000 increased 13% to $2.6 billion from $2.3 billion. The increase was due to the increase in natural gas prices, the write down to market value of a CSW available-for-sale investment in a Chilean-based electric company sold in December 2000 and the effect of a gain in 1999 on the planned sale of a 50% interest in a cogeneration project. Federal law limits ownership in qualifying cogeneration facilities to 50%. CSW Energy constructed the project and completed the sale of a 50% interest in the project to an unaffiliated entity in 1999. Expenses of the worldwide electric and gas operations increased in 1999 due to the addition of expenses of businesses acquired in December 1998 and the start of commercial operation of the two-unit 250 MW coal-fired generating plant in China.

Interest and Preferred Dividends

In 2000 interest and preferred stock dividends increased by 16% to $1,160 million from $996 million in 1999 due to additional interest expense from the ruling on the litigation with the government disallowing COLI tax deductions and AEP's intention to maintain flexibility for corporate separation by issuing short-term debt at flexible rates. The use of fixed interest rate swaps has been employed to mitigate the risk from floating interest rates.

The 11% increase in interest and preferred stock dividends in 1999 was due primarily to increased interest expense on long-term debt. Long-term debt outstanding increased $564 million in 1999.

Other Income

Other income decreased from $139 million in 1999 to $33 million in 2000 primarily due to a write-down of AEP's Yorkshire investment to reflect a proposed sale in 2001, losses of non-regulated subsidiaries accounted for on an equity basis, and a charge for the discontinuance of an electric storage water heater demand side management program.

Other income increased 46% in 1999 primarily due to gains from the sale of investments at SEEBOARD and from interest income related to a cogeneration power plant.

Income Taxes

Income taxes increased in 2000 primarily due to an unfavorable ruling in AEP's suit against the government over interest deductions claimed relating to AEP's COLI program and nondeductible merger related costs.

Industry Restructuring

In 2000 California's deregulated energy market suffered problems including high energy prices, short energy supply, and financial difficulties for retail energy suppliers whose prices to customers are controlled. This energy crisis has highlighted the importance of risk management and has contributed to certain state regulatory and legislative actions which could delay the start of customer choice and the transition to competitive, market based pricing for retail electricity supply in some of the states in which the AEP System operates. Seven of the eleven state retail jurisdictions in which the AEP domestic electric utility companies operate have enacted restructuring legislation. In general, the legislation provides for a transition from cost-based regulation of bundled electric service to customer choice and market pricing for the supply of electricity. As legislative and regulatory proceedings evolve, six AEP electric operating companies (APCo, CPL, CSPCo, OPCo, SWEPCo and WTU) doing business in five of the seven states that have passed restructuring legislation have discontinued the application of SFAS 71 regulatory accounting for generation. The seven states in various stages of restructuring to transition generation to market based pricing are Arkansas, Michigan, Ohio, Oklahoma, Texas, Virginia, and West Virginia. AEP has not discontinued its regulatory accounting for its subsidiaries doing business in Michigan and Oklahoma pending the implementation of the legislation. The following is a summary of restructuring legislation, the status of the transition plans and the status of the electric utility companies' accounting to comply with the changes in each of the AEP System's seven state regulatory jurisdictions affected by restructuring legislation.

Ohio Restructuring

Effective January 1, 2001, customer choice of electricity supplier began under the Ohio Act. In February 2001, one supplier announced its plan to offer service to CSPCo's residential customers. Currently for residential customers of OPCo, no alternative suppliers have registered with the PUCO as required by the Ohio Act. Two alternative suppliers have been approved to compete for CSPCo's and OPCo's commercial and industrial customers. Presently, customers continue to be served by CSPCo and OPCo with a legislatively required residential rate reduction of 5% for the generation portion of rates and a freezing of generation rates including fuel rates starting on January 1, 2001.

The Ohio Act provides for a five-year transition period to move from cost based rates to market pricing for generation services. It granted the PUCO broad oversight responsibility for promulgation of rules for competitive retail electric generation service, approval of a transition plan for each electric utility company and addressing certain major transition issues including unbundling of rates and the recovery of stranded costs including regulatory assets and transition costs.

The Ohio Act also provides for a reduction in property tax assessments, the imposition of replacement franchise and income taxes, and the replacement of a gross receipts tax with a KWH based excise tax. The property tax assessment percentage on generation property was lowered from 100% to 25% of value effective January 1, 2001 and Ohio electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which Ohio electric utilities will pay the excise tax based on gross receipts is the tax year ending April 30, 2002. As of May 1, 2001 electric distribution companies will be subject to an excise tax based on KWH sold to Ohio customers. The gross receipts tax is paid at the beginning of the tax year (May 1), deferred by CSPCo and OPCo as a prepaid expense and amortized to expense during the tax year pursuant to the tax law whereby the payment of the tax results in the privilege to conduct business in the year following the payment of the tax. As a result a duplicate tax will be expensed from May 1, 2001 through April 30, 2002 adding approximately $90 million to tax expense during that period. Unless the companies can recover the duplicate amount from ratepayers it will negatively impact results of operations.

On September 28, 2000, the PUCO approved, with minor modifications, a stipulation agreement between CSPCo, OPCo, the PUCO staff, the Ohio Consumers' Counsel and other concerned parties regarding transition plans filed by CSPCo and OPCo. The key provisions of this stipulation agreement are:

- Recovery of generation-related regulatory assets at December 31, 2000 over seven years for OPCo ($518 million) and over eight years for CSPCo ($248 million) through frozen transition rates for the first five years of the recovery period and a wires charge for the remaining years.
- A shopping incentive (a price credit) of 2.5 mills per KWH for the first 25% of CSPCo residential customers that switch suppliers. There is no shopping incentive for OPCo customers.
- The absorption of $40 million by CSPCo and OPCo ($20 million per company) of consumer education, implementation and transition plan filing costs with deferral of the remaining costs, plus a carrying charge, as a regulatory asset for recovery in future distribution rates.
- CSPCo and OPCo will make available a fund of up to $10 million to reimburse customers who choose to purchase their power from another company for certain transmission charges imposed by PJM and/or a Midwest ISO on generation originating in the Midwest ISO or PJM areas.
- The statutory 5% reduction in the generation component of residential tariffs will remain in effect for the entire five year transition period.
- The companies' request for a $90 million gross receipts tax rider to recover the duplicate gross receipts KWH based excise tax would be considered separately by the PUCO.

The approved stipulation agreement also accepted the following provisions contained in CSPCo's and OPCo's filed transition plans:

- a corporate separation plan to segregate generation, transmission and distribution assets into separate legal entities, and
- a plan for independent operation of transmission facilities.

The gross receipts tax issue was considered by the PUCO in hearings held in June 2000. In the September 28, 2000 order approving the stipulation agreement, the PUCO determined that there was no duplicate tax overlap period and denied the request for a $90 million gross receipts tax rider. CSPCo's and OPCo's request for rehearing of the gross receipts tax issue was denied. An appeal of this issue to the Ohio Supreme Court has been filed. Unless this issue is resolved in the companies' favor, it will have an adverse effect on future results of operations and financial position.

One of the intervenors at the hearings for approval of the settlement agreement (whose request for rehearing was denied by the PUCO) has filed with the Ohio Supreme Court for review of the settlement agreement including recovery of regulatory assets. Management is unable to predict the outcome of litigation but the resolution of this matter could negatively impact results of operation.

Beginning January 1, 2001, CSPCo's and OPCo's fuel costs will not be subject to PUCO fuel recovery proceedings. Deferred fuel costs at December 31, 2000 which represent under or over recoveries were one of the items included in the PUCO's final determination of net regulatory assets to be collected (recovered) during the transition period. The elimination of fuel clause recoveries in 2001 in Ohio will subject AEP, CSPCo and OPCo to the risk of fuel market price increases and could adversely affect their future results of operations and cash flows.

CSPCo and OPCo Discontinue Application of SFAS 71 Regulatory Accounting for the Ohio Jurisdiction

In September 2000 CSPCo and OPCo discontinued the application of SFAS 71 for their Ohio retail jurisdictional generation business since generation is no longer cost-based regulated in the Ohio jurisdiction and management was able to determine their transition rates and wires charges. The discontinuance in the Ohio jurisdiction was possible as a result of the PUCO's September 28, 2000 approval of the stipulation agreement which established rates, wires charges and net regulatory asset recovery procedures during the transition to market rates.

CSPCo's and OPCo's discontinuance of SFAS 71 for generation resulted in after tax extraordinary losses in the third quarter of 2000 of $25 million and $19 million, respectively, due to certain unrecoverable generation-related regulatory assets and transition expenses. Management believes that substantially all of the remaining net regulatory assets related to the Ohio generation business will be recovered under the PUCO's September 28, 2000 order. Therefore, under the provisions of EITF 97-4, CSPCo's and OPCo's generation-related recoverable net regulatory assets were transferred to the transmission and distribution portion of the business and will be amortized as they are recovered through transition rates to customers. CSPCo and OPCo performed an accounting impairment analysis on their generating assets under SFAS 121 as required when discontinuing the application of SFAS 71 and concluded there was no impairment of generation assets.

Virginia Restructuring

In Virginia, a restructuring law provides for a transition to choice of electricity supplier for retail customers beginning on January 1, 2002. In February 2001, restructuring revision legislation was approved by the Virginia Legislature which could modify the terms of restructuring. Presently, the transition period is to be completed, subject to a finding by the Virginia SCC that an effective competitive market exists by January 1, 2004 but no later than January 1, 2005.

The restructuring law also provides an opportunity for recovery of just and reasonable net stranded generation costs. The mechanisms in the Virginia law for net stranded cost recovery are: a capping of rates until as late as July 1, 2007, and the application of a wires charge upon customers who depart the incumbent utility in favor of an alternative supplier prior to the termination of the rate cap. The restructuring law provides for the establishment of capped rates prior to January 1, 2001 based either on a request by APCo for a change in rates prior to January 1, 2001 or on the rates in effect at July 1, 1999 if no rate change request is made and the establishment of a wires charge by the fourth quarter of 2001. APCo did not request new rates; therefore, its current rates are the capped rates. In the third quarter of 2000, the Virginia SCC directed APCo to file a cost of service study using 1999 as a test year to review the reasonableness of APCo's capped rates. The cost of service study was filed on January 3, 2001. In the opinion of AEP's Virginia counsel, Virginia's restructuring law does not permit the Virginia SCC to change rates for the transition period except for changes in the fuel factor, changes in state gross receipts taxes, or to address the utility's financial distress. However, if the Virginia SCC were to reduce APCo's capped rates or deny recovery of regulatory assets, it would adversely affect results of operations if such action is ultimately determined to be legal.

The Virginia restructuring law also requires filings to be made that outline the functional separation of generation from transmission and distribution and a rate unbundling plan. On January 3, 2001, APCo filed its corporate separation plan and rate unbundling plan with the Virginia SCC which is based on the most recent rate case test year (1996). See above for a discussion of AEP's corporate separation plan filed with the SEC.

West Virginia Restructuring

On January 28, 2000, the WVPSC issued an order approving an electricity restructuring plan for WV. On March 11, 2000, the WV Legislature approved the restructuring plan by joint resolution. The joint resolution provides that the WVPSC cannot implement the plan until the legislature makes necessary tax law changes to preserve the revenues of the state and local governments. The Joint Committee on Government and Finance of the WV Legislature hired a consultant to study and issue a report on the tax changes required to implement electric restructuring. Moreover, the committee also hired a consultant to study and issue a report on the electric restructuring plan in light of events occurring in California. The WV Legislature is not expected to consider these reports until the 2002 Legislative Session since the 2001 Legislative Session ends in April 2001. Since the WV Legislature has not yet passed the required tax law changes, the restructuring plan has not become effective. AEP subsidiaries, APCo and WPCo, provide electric service in WV.

The provisions of the restructuring plan provide for customer choice to begin after all necessary rules are in place (the "starting date"); deregulation of generation assets on the starting date; functional separation of the generation, transmission and distribution businesses on the starting date and their legal corporate separation no later than January 1, 2005; a transition period of up to 13 years, during which the incumbent utility must provide default service for customers who do not change suppliers unless an alternative default supplier is selected through a WVPSC-sponsored bidding process; capped and fixed rates for the 13 year transition period as discussed below; deregulation of metering and billing; a 0.5 mills per KWH wires charge applicable to all retail customers for a 10-year period commencing with the starting date intended to provide for recovery of any stranded cost including net regulatory assets; establishment of a rate stabilization deferred liability balance of $81 million ($76 million by APCo and $5 million by WPCo) by the end of year ten of the transition period to be used as determined by the WVPSC to offset market prices paid in the eleventh, twelfth, and thirteenth year of the transition period by residential and small commercial customers that do not choose an alternative supplier.

Default rates for residential and small commercial customers are capped for four years after the starting date and then increase as specified in the plan for the next six years. In years eleven, twelve and thirteen of the transition period, the power supply rate shall equal the market price of comparable power. Default rates for industrial and large commercial customers are discounted by 1% for four and a half years, beginning July 1, 2000, and then increased at pre-defined levels for the next three years. After seven years the power supply rate for industrial and large commercial customers will be market based. APCo's Joint Stipulation agreement, discussed in Note 5 of the Notes to Consolidated Financial Statements, which was approved by the WVPSC on June 2, 2000 in connection with a base rate filing, also provides additional mechanisms to recover regulatory assets.

APCo Discontinues Application of SFAS 71 Regulatory Accounting

In June 2000 APCo discontinued the application of SFAS 71 for its Virginia and WV retail jurisdictional portions of its generation business since generation is no longer considered to be cost-based regulated in those jurisdictions and management was able to determine APCo's transition rates and wires charges. The discontinuance in the WV jurisdiction was made possible by the June 2, 2000 approval of the Joint Stipulation which established rates, wires charges and regulatory asset recovery procedures for the transition period to market rates which was determined to be probable. APCo was also able to discontinue application of SFAS 71 for the generation portion of its Virginia retail jurisdiction after management decided that APCo would not request capped rates different from its current rates. The existence of effective restructuring legislation in Virginia and the probability that the WV legislation would become effective with the expected probable passage of required enabling tax legislation in 2001 supported management's decision in 2000 to discontinue SFAS 71 regulatory accounting for APCo's electricity generation and supply business.

APCo's discontinuance of SFAS 71 for generation resulted in an after tax extraordinary gain, in the second quarter of 2000, of $9 million. Management believes that it is probable that substantially all net regulatory assets related to the Virginia and WV generation business will be recovered. Therefore, under the provisions of EITF 97-4, APCo's generation-related net regulatory assets were transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, APCo performed an accounting impairment analysis on its generating assets under SFAS 121 and concluded that there was no accounting impairment of generation assets.

The recent energy crisis in California, discussed above, may be having a chilling effect on efforts to enact the required tax change legislation in West Virginia. The WV Legislature could decide not to enact the required tax changes, thereby, effectively continuing cost based rate regulation in West Virginia or it could modify the restructuring plan. Modifications in the restructuring plan could adversely affect future results of operations if they were to occur. Management is carefully monitoring the situation in West Virginia and continues to work with all concerned parties to get approval to successfully transition our generation business in West Virginia. Failure to pass the required enabling tax changes could ultimately require APCo to re-instate regulatory accounting principles under SFAS 71 for its generation operations in West Virginia.

Arkansas Restructuring

In 1999 legislation was enacted in Arkansas that will ultimately restructure the electric utility industry. Its major provisions are:

- retail competition begins January 1, 2002 but can be delayed until as late as June 30, 2003 by the Arkansas Commission;
- transmission facilities must be operated by an ISO if owned by a company which also owns generation assets;
- rates will be frozen for one to three years;
- market power issues will be addressed by the Arkansas Commission; and
- an annual progress report to the Arkansas General Assembly on the development of competition in electric markets and its impact on retail customers is required.

In November 2000 the Arkansas Commission filed its annual progress report with the Arkansas General Assembly recommending a delay in the start date of retail competition to a date between October 1, 2003 and October 1, 2005. The report also asks the Arkansas General Assembly to delegate authority to the Arkansas Commission to determine the appropriate retail competition start date within the approved time frame. In February 2001 the Arkansas General Assembly passed legislation that was signed into law by the Governor that changes the date of electric retail competition to October 1, 2003, and provides the Arkansas Commission with the authority to delay that date for up to two years.

Texas Restructuring

In June 1999 Texas restructuring legislation was signed into law which, among other things:

- gives Texas customers of investor-owned utilities the opportunity to choose their electricity provider beginning January 1, 2002;

- provides for the recovery of regulatory assets and of other stranded costs through securitization and non-bypassable wires charges;
- requires reductions in NOx and sulfur dioxide emissions;
- provides for a rate freeze until January 1, 2002 followed by a 6% rate reduction for residential and small commercial customers and a number of customer protections;
- provides for an earnings test for each of the three years of the rate freeze period (1999 through 2001) which will reduce stranded cost recoveries or if there is no stranded cost provides for a refund or their use to fund certain capital expenditures in the amount of the excess earnings;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution utility;
- provides for certain limits for ownership and control of generating capacity by companies;
- provides for elimination of the fuel clause reconciliation process beginning January 1, 2002; and
- provides for a 2004 true-up proceeding to determine recovery of stranded costs including final fuel recovery balances, net regulatory assets, certain environmental costs, accumulated excess earnings and other issues.

Under the Texas Legislation, delivery of electricity will continue to be the responsibility of the local electric transmission and distribution utility company at regulated prices. Each electric utility was required to submit a plan to structurally unbundle its business activities into a retail electric provider, a power generation company, and a transmission and distribution utility. In May 2000 CPL, SWEPCo and WTU filed a revised business separation plan that the PUCT approved on July 7, 2000 in an interim order. The revised business separation plans provided for CPL and WTU, which operate in Texas only, to establish separate companies and divide their integrated utility operations and assets into a power generation company, a transmission and distribution utility and a retail electric provider. SWEPCo will separate its Texas jurisdictional transmission and distribution assets and operations into a new Texas regulated transmission and distribution subsidiary. In addition, a retail electric provider will be formed by SWEPCo to provide retail electric service to SWEPCo's Texas jurisdictional customers.

Under the Texas Legislation, electric utilities are allowed, with the approval of the PUCT, to recover stranded generation costs including generation-related regulatory assets that may not be recoverable in a future competitive market. The approved stranded costs can be refinanced through securitization, which is a financing structure designed to provide lower financing costs than are available through conventional financings. Lower financing costs are achieved through the issuance of securitization bonds at a lower interest rate to finance 100% of the costs pursuant to a state pledge to ensure recovery of the bond principal and financing costs through a non-bypassable rate surcharge by the regulated transmission and distribution utility over the life of the securitization bonds.

In 1999 CPL filed an application with the PUCT to securitize approximately $1.27 billion of its retail generation-related regulatory assets and approximately $47 million in other qualified restructuring costs. On March 27, 2000, the PUCT issued an order permitting CPL to securitize approximately $764 million of net regulatory assets. The PUCT's order authorized issuance of up to $797 million of securitization bonds including the $764 million for recovery of net generation-related regulatory assets and $33 million for other qualified refinancing costs. The $764 million for recovery of net generation-related regulatory assets reflects the recovery of $949 million of generation-related regulatory assets offset by $185 million of customer benefits associated with accumulated deferred income taxes. CPL had previously proposed in its filing to flow these benefits back to customers over the 14-year term of the securitization bonds. On April 11, 2000, four parties appealed the PUCT's securitization order to the Travis County District Court. In July 2000 the Travis County District Court upheld the PUCT's securitization order. The securitization order is being appealed to the Supreme Court of Texas. One of these appeals challenges CPL's ability to recover securitization charges under the Texas Constitution. CPL will not be able to issue the securitization bonds until these appeals are resolved.

The remaining regulatory assets of $206 million originally included by CPL in its 1999 securitization request were included in a March 2000 filing with the PUCT, requesting recovery of an additional $1.1 billion of stranded costs. The March 2000 filing of $1.1 billion included recovery of approximately $800 million of STP costs included in property, plant and equipment-electric on the Consolidated Balance Sheets. These STP costs had previously been identified as excess cost over market (ECOM) by the PUCT for regulatory purposes and were earning a lower return and were being amortized on an accelerated basis for rate-making purposes in Texas. The March 2000 filing will determine the initial amount of stranded costs in addition to the securitized regulatory assets to be recovered beginning January 1, 2002.

CPL submitted a revised estimate of stranded costs on October 2, 2000 using assumptions developed in generic proceedings by the PUCT and an administrative model developed by the PUCT staff that reduced the amount of the initial stranded cost estimate to $361 million from the $1.1 billion requested by CPL. CPL subsequently agreed to accept adjustments proposed by intervenors that reduced ECOM to approximately $230 million. Hearings on CPL's requested ECOM were held in October 2000. In February 2001 the PUCT issued an interim decision determining an initial amount of CPL ECOM or stranded costs of negative $580 million. The decision indicated that CPL's costs were below market after securitization of regulatory assets. Management does not agree with the critical inputs to this model. Management believes CPL has a positive stranded cost exclusive of securitized regulatory assets. The final amount of CPL's stranded costs including regulatory assets and ECOM will be established by the PUCT in the legislatively required 2004 true-up proceeding. If CPL's total stranded costs determined in the 2004 true-up are less than the amount of securitized regulatory assets, the PUCT can implement an offsetting credit to transmission and distribution rates.

The PUCT ruled that prior to the 2004 true-up proceeding, no adjustments would be made to the amount of regulatory costs authorized by the PUCT to be securitized. However, the PUCT also ruled that excess earnings for the period 1999-2001 should be refunded through transmission and distribution rates to the extent of any over-mitigation of stranded costs represented by negative ECOM. In the event that CPL will be required to refund excess earnings in the future instead of applying them to reduce ECOM or regulatory assets, it will adversely affect future cash flow but not results of operations since excess earnings for 1999 and 2000 were accrued and expensed in 1999 and 2000. The Texas Legislation allows for several alternative methods to be used to value stranded costs in the final 2004 true-up proceeding including the sale or exchange of generation assets, the issuance of power generation company stock to the public or the use of PUCT staff's ECOM model. To the extent that the final 2004 true-up proceeding determines that CPL should recover additional stranded costs, the total amount recoverable can be securitized.

The Texas Legislation provides that each year during the 1999 through 2001 rate freeze period, electric utilities are subject to an earnings test. For electric utilities with stranded costs, such as CPL, any earnings in excess of the most recently approved cost of capital in its last rate case must be applied to reduce stranded costs. Utilities without stranded costs, such as SWEPCo and WTU, must either flow such excess earnings amounts back to customers or make capital expenditures to improve transmission or distribution facilities or to improve air quality. The Texas Legislation requires PUCT approval of the annual earnings test calculation.

The 1999 earnings test reports filed by CPL, SWEPCo and WTU showed excess earnings of $21 million, $1 million and zero, respectively. The PUCT staff issued its report on the excess earnings calculations filed by CPL, SWEPCo and WTU and calculated the excess earnings amounts to be $41 million, $3 million and $11 million for CPL, SWEPCo and WTU, respectively. The Office of Public Utility Counsel also filed exceptions to the companies' earnings reports. Several issues were resolved via settlement and the remaining open issues were submitted to the PUCT. A final order was issued by the PUCT in February 2001 and adjustments to the accrued 1999 and 2000 excess earnings were recorded in results of operations in the fourth quarter of 2000. After adjustments the accruals for 1999 excess earnings for CPL and WTU were $24 million and $1 million, respectively. CPL and WTU also recorded an estimated provision for excess 2000 earnings of $16 million and $14 million, respectively.

A Texas settlement agreement in connection with the AEP and CSW merger permits CPL to apply for regulatory purposes up to $20 million of STP ECOM plant assets a year in 2000 and 2001 to reduce excess earnings, if any. For book and financial reporting purposes, STP ECOM plant assets will be depreciated in accordance with GAAP, on a systematic and rational basis unless impaired. CPL will establish a regulatory liability or reduce regulatory assets by a charge to earnings to the extent excess earnings exceed $20 million in 2000 and 2001.

Beginning January 1, 2002, fuel costs will not be subject to PUCT fuel reconciliation proceedings. Consequently, CPL, SWEPCo and WTU will file a final fuel reconciliation with the PUCT to reconcile their fuel costs through the period ending December 31, 2001. Fuel costs have been reconciled by CPL, SWEPCo and WTU through June 30, 1998, December 31, 1999 and June 30, 1997, respectively. WTU is currently reconciling its fuel through June 2000. See discussion in Note 5 of the Notes to Consolidated Financial Statements. At December 31, 2000, CPL's, SWEPCo's and WTU's Texas jurisdictional unrecovered deferred fuel balances were $127 million, $20 million and $59 million, respectively. Final unrecovered deferred fuel balances at December 31, 2001 will be included in each company's 2004 true-up proceeding. If the final fuel balances or any amount incurred but not yet reconciled were not recovered, they could have a negative impact on results of operations. The elimination of the fuel clause recoveries in 2002 in Texas will subject AEP, CPL, SWEPCo and WTU to greater risks of fuel market price increases and could adversely affect future results of operations beginning in 2002.

The affiliated retail electric provider of CPL, SWEPCo and WTU will be required to offer residential and small commercial customers (with a peak usage of less than 1000 KW) a rate 6% below rates in effect on January 1, 1999 adjusted for any changes in fuel cost recovery factors since January 1, 1999 (price to beat). The price to beat must be offered to residential and small commercial customers until January 1, 2007. Customers with a peak usage of more than 1000 KW are subject to market rates. The Texas restructuring legislation provides for the price to beat to be adjusted up to two times annually to reflect significant changes in fuel and purchased energy costs.

Discontinuance of the Application of SFAS 71 Regulatory Accounting in Arkansas and Texas

The financial statements of CPL, SWEPCo and WTU have historically reflected the economic effects of regulation by applying the requirements of SFAS 71. As a result of the scheduled deregulation of generation in Arkansas and Texas, the application of SFAS 71 for the generation portion of the business in those states was discontinued in the third quarter of 1999. Under the provisions of EITF 97-4, CPL's generation-related net regulatory assets were transferred to the distribution portion of the business and will be amortized as they are recovered through wires charges to customers. Management believes that substantially all of CPL's generation-related regulatory assets will be recovered under the Texas Legislation. CPL's recovery of generation-related regulatory assets and stranded costs are subject to a final determination by the PUCT in 2004. If future events were to make the recovery through securitization of CPL's generation-related regulatory assets no longer probable, CPL would write-off the portion of such regulatory assets deemed unrecoverable as a non-cash extraordinary charge to earnings.

The Texas Legislation provides that all finally determined stranded costs will be recovered. Since SWEPCo and WTU are not expected to have net stranded costs, all Arkansas and Texas jurisdictional generation-related net regulatory assets were written off as non-recoverable in 1999 when they discontinued application of SFAS 71 regulatory accounting. As required by SFAS 101 when SFAS 71 is discontinued, an accounting impairment analysis for generation assets under SFAS 121 was completed for CPL, SWEPCo and WTU. The analysis showed that there was no accounting impairment of generation assets when the application of SFAS 71 was discontinued.

CPL, SWEPCo and WTU will test their generation assets for impairment under SFAS 121 if circumstances change. Management believes that on a discounted basis CPL's generation business net cash flows will likely be less than its generating assets' net book value and together with its generation-related regulatory assets should create a recoverable stranded cost for regulatory purposes under the Texas Legislation. Therefore, manage-ment continues to carry on the balance sheet at December 31, 2000, $953 million of generation-related regulatory assets already approved for securitization and $195 million of net generation-related regulatory assets pending approval for securitization in Texas. A final determination of whether they will be securitized and recovered will be made as part of the 2004 true-up proceeding.

CPL, SWEPCo, and WTU continue to analyze the impact of electric utility industry restructuring legislation on their Arkansas and Texas electric operations. Although management believes that the Texas Legislation provides for full recovery of stranded costs and that the companies do not have a recordable accounting impairment, a final determination of whether CPL will experience an accounting loss or whether SWEPCo and WTU will experience any additional accounting loss from an inability to recover generation-related regulatory assets and other restructuring related costs in Texas and Arkansas cannot be made until such time as the regulatory process is complete following the 2004 true-up proceeding in Texas and a determination by the Arkansas Commission. In the event CPL, SWEPCo, and WTU are unable after the 2004 true-up proceeding and after the Arkansas Commission proceedings to recover all or a portion of their generation-related regulatory assets, stranded costs and other restructuring related costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Although Arkansas' delay of retail competition may be having a negative effect on the progress of efforts to transition AEP's generation in Arkansas to market based pricing of electricity, it appears that Texas is moving forward as planned. Management is carefully monitoring the situation in Arkansas and is working with all concerned parties to prudently quicken the pace of the transition. However, changes could occur due to concerns stemming from the California energy crisis and other events which could adversely affect future results of operations in Arkansas and possibly Texas.

Michigan Restructuring

On June 5, 2000, the Michigan Legislation became law. Its major provisions, which were effective immediately, applied only to electric utilities with one million or more retail customers. I&M, AEP's electric operating subsidiary doing business in Michigan, has less than one million customers in Michigan. Consequently, I&M was not immediately required to comply with the Michigan Legislation.

The Michigan Legislation gives the MPSC broad power to issue orders to implement retail customer choice of electric supplier no later than January 1, 2002 including recovery of regulatory assets and stranded costs. On October 2, 2000, I&M filed a restructuring implementation plan as required by a MPSC order. The plan identifies I&M's proposal to file with the MPSC on June 5, 2001 its unbundled rates, open access tariffs, terms of service and supporting schedules. Described in the plan are I&M's intentions and preparation for competition related to supplier transactions, customer transactions, rate unbundling, education programs, and regional transmission organization. The plan contains a proposed methodology to determine stranded costs and implementation costs and requests the continuation of a wires charge for recovery of nuclear decommissioning costs. Approval of the restructuring implementation plan is pending before the MPSC.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan will continue to be cost-based regulated until the MPSC approves rates and wires charges in 2001. The establishment of rates and wires charges under a MPSC approved transition plan will enable management to determine the ability to recover stranded costs including regulatory assets and other implementation costs, a requirement of EITF 97-4 to discontinue the application of SFAS 71.

Upon the discontinuance of SFAS 71, I&M will, if necessary, have to write off its Michigan jurisdictional generation-related regulatory assets and record its unrecorded Michigan jurisdictional liability for decommissioning the Cook Plant to the extent that they cannot be recovered under the transition rates and wires charges. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, I&M will have to perform an accounting impairment analysis under SFAS 121 to determine if the Michigan jurisdictional portion of its generating assets are impaired for accounting purposes.

The amount of regulatory assets recorded on the books at December 31, 2000 applicable to I&M's Michigan retail jurisdictional generation business is approximately $45 million before related tax effects. The estimated unrecorded liability for the Michigan jurisdiction to decommission the Cook Plant ranges from $114 million to $215 million in 2000 non-discounted dollars based upon studies completed during 2000. For the Michigan jurisdiction the Company has accumulated approximately $100 million in trust funds to decommission the Cook Plant. Based on the current information available, management does not anticipate that I&M will experience any material tangible asset accounting impairment or regulatory asset write-offs. Ultimately, however, whether I&M will experience material regulatory asset write-offs will depend on whether the MPSC approves their recovery in future restructuring proceedings.

A determination of whether I&M will experience any asset impairment loss regarding its Michigan retail jurisdictional generating assets and any loss from a possible inability to recover Michigan generation-related regulatory assets, decommissioning obligations and transition costs cannot be made until such time as the rates and the wires charges are determined through the regulatory process. In the event I&M is unable to recover all or a portion of its generation-related regulatory assets, unrecorded decommissioning obligation, stranded costs and other implementation costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Oklahoma Restructuring

In 1997, the Oklahoma Legislature passed restructuring legislation providing for retail open access by July 1, 2002. That legislation called for a number of studies to be completed on a variety of restructuring issues, including an independent system operator, technical, financial, transition and consumer issues. During 1998 and 1999 several of the studies were completed.

The information from the studies was expected to be used in the development of additional industry restructuring legislation during the 2000 legislative session. Several additional electric industry restructuring bills were filed in the 2000 Oklahoma legislative session. The proposed bills generally supple-mented the industry restructuring legislation previously enacted in Oklahoma which lacked specific procedures for a transition to market based competitive prices. The industry restructuring legislation previously passed did not delegate the establishment of transition procedures to the Oklahoma Corporation Commission. The 2000 Oklahoma legislative session adjourned in May without passing further restructuring legislation.

The 2001 Oklahoma legislative session convened in early February. No further electric restructuring legislation has passed and proposals have been made to delay the implementation of the transition to customer choice and market based pricing under the restructuring legislation. These proposals are a reaction to California's recent energy crisis. Management is working with all concerned parties to reassure them that what happened in California will not occur in Oklahoma. If the necessary legislation is not passed, the Company's generation and retail electric supply business will remain regulated in Oklahoma. If implementation legislation were to modify the original restructuring legislation in Oklahoma it could have a adverse effect on results of operations.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since PSO's rates for generation in Oklahoma will continue to be cost-based regulated until the Oklahoma Legislature approves further restructuring legislation and transition rates and wires charges are established under an approved transition plan. Until management is able to determine the ability to recover stranded costs which includes regulatory assets and other implementation costs, PSO cannot discontinue application of SFAS 71 accounting under GAAP.

When PSO discontinues application of SFAS 71, it will be necessary to write off Oklahoma jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the transition rates and wires charges, when determined, and record any asset accounting impairments in accordance with SFAS 121.

A determination of whether PSO will experience any asset impairment loss regarding its Oklahoma retail jurisdictional generating assets and any loss from a possible inability to recover Oklahoma generation-related regulatory assets and other transition costs cannot be made until such time as the rates and the wires charges are determined through the legislative and/or regulatory process. In the event PSO is unable to recover all or a portion of its generation-related regulatory assets and implementation costs, Oklahoma restructuring could have a material adverse effect on results of operations and cash flows.

Restructuring In Other Jurisdictions

The remaining four states (Indiana, Kentucky, Louisiana and Tennessee) making up our service territory have initiatives to implement or review customer choice, although the timing of any implementation is uncertain and may be further delayed due to the California situation. The Company supports customer choice and deregulation of generation and is proactively involved in discussions regarding the best competitive market structure and transition method to arrive at a fair, competitive marketplace. As the pricing of generation in these markets evolves from regulated cost-of-service rates to market-based pricing, the recovery of stranded costs including net regulatory assets and other transition costs must be addressed. The amount of stranded costs the Company could experience when and if restructuring occurs in these jurisdictions depends on the timing and extent to which competition is introduced to its business and the future market prices of electricity. The recovery of stranded cost is dependent on the terms of future legislation and, if required, related regulatory proceedings.

Customer choice and the transition to market based competition if restructuring is implemented in Indiana, Kentucky, Louisiana and Tennessee could also ultimately result in adverse impacts on results of operations and cash flows depending on the future market prices of electricity and the ability of the Company to recover its stranded costs including net regulatory assets during a transition or subsequent period through a wires charge or other recovery mechanism. We believe that state restructuring legislation and the regulatory process should provide for full recovery of generation-related net regulatory assets and other reasonable stranded costs if these states decide to deregulate generation. However, if in the future any portion of AEP's generation business in these other jurisdictions were to no longer be cost-based regulated and if it were not possible to demonstrate probability of recovery of resultant stranded costs including regulatory assets, results of operations, cash flows and financial condition would be adversely affected.

Amortization of Transition Regulatory Assets and Other Deferred Costs

Future earnings will be negatively impacted by amortization of certain deferred costs and regulatory assets related to the Cook Plant extended outage, transition plans to discontinue SFAS 71 regulatory accounting for generation with the beginning of customer choice in certain states and the merger of AEP and CSW.

During 1999, the IURC and MPSC approved settlement agreements which provided for the deferral in 1999 and amortization of restart costs and fuel-related revenues from the extended Cook Plant outage. The amortization period is for five years ending in December 2003. Annual amortization is $78 million. See Note 4 of the Notes to Consolidated Financial Statements.

Beginning in 2001 under the Ohio Act, CSPCo and OPCo began amortizing their transition regulatory assets over eight and seven years, respectively. The annual amortization in 2001 for CSPCo and OPCo is estimated to be $20 million and $74 million, respectively. The amount of amortization is based upon KWH sold.

APCo began amortization of its West Virginia jurisdictional regulatory assets over an eleven year period in July 2000. In the Virginia jurisdiction, APCo started straight line amortization of regulatory assets over a seven year period in July 2000. The annual amortization for 2001 is $9 million for the West Virginia jurisdiction and $9 million for the Virginia jurisdiction.

In June 2000 AEP merged with CSW. In connection with securing approval for the merger the Company signed agreements, approved by regulatory authorities, which included rate reductions to share estimated merger savings with customers. The agreements provide for rate reductions for periods up to eight years beginning in the third quarter of 2000.

Certain merger related costs recoverable from ratepayers were deferred pursuant to the settlement agreements and will be amortized over five to eight years depending upon the terms of the respective agreements. The annual amortization of the deferred merger costs is estimated to be $8 million in 2001. If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements and the amortization of deferred merger-related costs, future results of operations, cash flows and possibly financial condition could be adversely affected. See Note 3 of the Notes to Consolidated Financial Statements for further discussion of the merger.

Amortization of the above described deferred costs and regulatory assets could negatively affect future earnings to the extent that they exceed cost savings or revenues growth.

Litigation

COLI

On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against AEP in its suit against the United States over deductibility of interest claimed by AEP in its consolidated federal income tax return related to its COLI program. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 the Company paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced by $319 million in 2000. The Company plans to appeal the decision.

Shareholders' Litigation

On June 23, 2000, a complaint was filed in the U.S. District Court for the Eastern District of New York seeking unspecified compensatory damages against AEP and four former or present officers. The individual plaintiff also seeks certification as the representative of a class consisting of all persons and entities who purchased or otherwise acquired AEP common stock between July 25, 1997, and June 25, 1999. The complaint alleges that the defendants knowingly violated federal securities laws by disseminating materially false and misleading statements concerning, among other things, the undisclosed materially impaired condition of the Cook Plant, AEP's inability to properly monitor, manage, repair, supervise and report on operations at the Cook Plant and the materially adverse conditions these problems were having, and would continue to have, on AEP's deteriorating financial condition, and ultimately on AEP's operations, liquidity and stock price. Four other similar class action complaints have been filed and the court has consolidated the five cases. The plaintiffs filed a consolidated complaint pursuant to this court order. This case has been transferred to the U.S. District Court for the Southern District of Ohio. Although, management believes these shareholder actions are without merit and intends to oppose them vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

Municipal Franchise Fee Litigation

CPL has been involved in litigation regarding municipal franchise fees in Texas as a result of a class action suit filed by the City of San Juan, Texas in 1996. The City of San Juan claims CPL underpaid municipal franchise fees and seeks damages of up to $300 million plus attorney's fees. CPL filed a counterclaim for overpayment of franchise fees.

During 1997, 1998 and 1999 the litigation moved procedurally through the Texas Court System and was sent to mediation without resolution.

In 1999 a class notice was mailed to each of the cities served by CPL. Over 90 of the 128 cities declined to participate in the lawsuit. However, CPL has pledged that if any final, non-appealable court decision awards a judgement against CPL for a franchise underpayment, CPL will extend the principles of that decision, with regard to any franchise underpayment, to the cities that declined to participate in the litigation. In December 1999, the court ruled that the class of plaintiffs would consist of approximately 30 cities. A trial date for June 2001 has been set.

Although management believes that it has substantial defenses to the cities' claims and intends to defend itself against the cities' claims and pursue its counterclaim vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

Texas Base Rate Litigation

In November 1995 CPL filed with the PUCT a request to increase its retail base rates by $71 million. In October 1997 the PUCT issued a final order which lowered CPL's annual retail base rates by $19 million from the rate level which existed prior to May 1996. The PUCT also included a "glide path" rate methodology in the final order pursuant to which annual rates were reduced by $13 million beginning May 1, 1998 with an additional annual reduction of $13 million commencing on May 1, 1999.

CPL appealed the final order to the Travis District Court. The primary issues being appealed include: the classification of $800 million of invested capital in STP as ECOM and assigning it a lower return on equity than other generation property; the use of the "glide path" rate reduction methodology; and an $18 million disallowance of service billings from an affiliate, CSW Services. As part of the appeal, CPL sought a temporary injunction to prohibit the PUCT from implementing the "glide path" rate reduction methodology. The temporary injunction was denied and the "glide path" rate reduction was implemented. In February 1999 the Travis District Court affirmed the PUCT order in regard to the three major items discussed above.

CPL appealed the Travis District Court's findings to the Texas Appeals Court which in July 2000, issued its opinion upholding the Travis District Court except for the disallowance of affiliated service company billings. Under Texas law, specific findings regarding affiliate transactions must be made by PUCT. In regards to the affiliate service billing issue, the findings were not complete in the opinion of the Texas Appeals Court who remanded the issue back to PUCT.

CPL has sought a rehearing of the Texas Appeals Court's opinion. The Texas Appeals Court has requested briefs related to CPL's rehearing request from interested parties. Management is unable to predict the final resolution of its appeal. If the appeal is unsuccessful the PUCT's 1997 order will continue to adversely affect results of operations and cash flows.

As part of the AEP/CSW merger approval process in Texas, a stipulation agreement was approved which resulted in the withdrawal of the appeal related to the "glide path" rate methodology. CPL will continue its appeal of the ECOM classification for STP property and the related loss of return on equity and the disallowed affiliated service billings.

Lignite Mining Agreement Litigation

SWEPCo and CLECO are each a 50% owner of Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. In 1982, SWEPCo and CLECO entered into a lignite mining agreement with DHMV, a partnership for the mining and delivery of lignite from a portion of these reserves.

In April 1997, SWEPCo and CLECO sued DHMV and its partners in U.S. District Court for the Western District of Louisiana seeking to enforce various obligations of DHMV under the lignite mining agreement, including provisions relating to the quality of delivered lignite, pricing, and mine reclamation practices. In June 1997, DHMV filed an answer denying the allegations in the suit and filed a counterclaim asserting various contract-related claims against SWEPCo and CLECO. SWEPCo and CLECO have denied the allegations contained in the counterclaims. In January 1999, SWEPCo and CLECO amended the claims against DHMV to include a request that the lignite mining agreement be terminated.

In April 2000, the parties agreed to settle the litigation. As part of the settlement, DHMV's interest in the mining operations and related debt and other obligations will be purchased by SWEPCo and CLECO. The closing date for the settlement has been extended from December 31, 2000 to March 31, 2001. The litigation has been stayed until April 2001 to give the parties time to consummate the settlement agreement.

Management believes that the resolution of this matter will not have a material effect on results of operations, cash flows or financial condition.

AEP is 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 the results of operations, cash flows or financial condition.

Environmental Concerns and Issues

As 2001 begins, the U.S. continues to debate an array of environmental issues affecting the electric utility industry. Most of the policies are aimed at reducing air emissions citing alleged impacts of such emissions on public health, sensitive ecosystems or the global climate.

AEP's policy on the environment continues to be the development and application of long-term economically feasible measures to improve air and water quality, limit emissions and protect the health of its employees, customers, neighbors and others impacted by its operations. In support of this policy, AEP continues to invest in research through groups like the Electric Power Research Institute and directly through demonstration projects for new technology for the capture and storage of carbon dioxide, mercury, NOx and other emissions. AEP intends to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to our customers at fair prices.

AEP has a proven record of efficiently producing and delivering electricity and gas while minimizing the impact on the environment. AEP and its subsidiaries have spent billions of dollars to equip their facilities with the latest cost effective clean air and water technologies and to research new technologies. We are proud of our award winning efforts to reclaim our mining properties.

The introduction of multi-pollutant control legislation is being discussed by members of Congress and the Bush Administration. The legislation being considered may regulate carbon dioxide, NOx, sulfur dioxide, mercury and other emissions from electric generating plants. Management will continue to support solutions which are based on sound science, economics and demonstrated control technologies. Management is unable to predict the timing or magnitude of additional pollution control laws or regulations. If additional control technology is required on AEP's facilities and their costs were not recoverable from ratepayers or through market based prices or volumes of product sold, they could adversely affect future results of operations and cash flows. The following discussions explains existing control efforts, litigation and other pending matters related to environmental issues for AEP System companies.

Federal EPA Complaint and Notice of Violation

Under the Clean Air Act, 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 AEP System has been involved in litigation regarding generating plant emissions under the Clean Air Act. In 1999 Notices of Violation were issued and complaints were filed by Federal EPA in various U.S. District Courts alleging the AEP System and eleven unaffiliated utilities made modifications to generating units at certain of their coal-fired generating plants over the course of the past 25 years that extended unit operating lives or increased unit generating capacity without a preconstruction permit in violation of the Clean Air Act. The complaint against the AEP System was amended in March 2000 to add allegations for certain generating units previously named in the complaint and to include additional AEP System generating units previously named only in the Notices of Violation in the complaint.

A number of northeastern and eastern states were granted leave to intervene in the Federal EPA's action against the AEP System under the Clean Air Act. A lawsuit against power plants owned by the AEP System alleging similar violations to those in the Federal EPA complaint and Notices of Violation was filed by a number of special interest groups and has been consolidated with the Federal EPA action.

The Clean Air Act 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). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts Federal EPA's contentions, could be substantial.

On May 10, 2000, the AEP System filed motions to dismiss all or portions of the complaints. Briefing on these motions was completed on August 2, 2000. On February 23, 2001, the government filed a motion for partial summary judgement seeking a determination that four projects undertaken on units at Sporn, Cardinal and Clinch River plants do not constitute "routine maintenance, repair and replacement" as used in the Clear Air Act. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense.

In the event the AEP System does 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 where states are deregulating generation, unbundled transition period generation rates, stranded cost wires charges and future market prices for electricity.

In December 2000 Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by AEP's subsidiary, CSPCo, reached a tentative agreement with Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. 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 which are 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 earnings.

NOx Reduction

Federal EPA issued a NOx rule that required substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. A number of utilities, including several AEP System companies, filed petitions seeking a review of the final rule in the D.C. Circuit Court. In March 2000, the D.C. Circuit Court issued a decision generally upholding the NOx rule. The D.C. Circuit Court issued an order in August 2000 which extends the final compliance date to May 31, 2004. In September 2000 following denial by the D.C. Circuit Court of a request for rehearing, the industry petitioners, including the AEP System companies, petitioned the U.S. Supreme Court for review, which was denied.

In December 2000 Federal EPA ruled that eleven states, including certain states in which the AEP System's generating units are located, failed to submit plans to comply with the mandates of the NOx rule. This determination means that those states could face stringent sanctions within the next 24 months including limits on construction of new sources of air emissions, loss of federal highway funding and possible Federal EPA takeover of state air quality management programs.

In January 2000 Federal EPA adopted a revised rule granting petitions filed by certain northeastern states under Section 126 of the Clean Air Act seeking significant reductions in nitrogen oxide emissions from utility and industrial sources. The rule imposes emissions reduction requirements comparable to the NOx rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Certain AEP companies and other utilities filed petitions for review in the D.C. Circuit Court. Briefing has been completed and oral argument was held in December 2000.

In a related matter, on April 19, 2000, the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NOx emissions from utility sources, including CPL and SWEPCo. The rule's compliance date is May 2003 for CPL and May 2005 for SWEPCo.

In June 2000 OPCo announced that it was beginning a $175 million installation of selective catalytic reduction technology (expected to be operational in 2001) to reduce NOx emissions on its two-unit 2,600 MW Gavin Plant. Construction of selective catalytic reduction technology on Amos Plant Unit 3, which is jointly owned by OPCo and APCo, and APCo's Mountaineer Plant is scheduled to begin in 2001. The Amos and Mountaineer projects (expected to be completed in 2002) are estimated to cost a total of $230 million.

Preliminary estimates indicate that compliance with the NOx rule upheld by the D.C. Circuit Court as well as compliance with the Texas Natural Resource Conservation Commission rule and the Section 126 petitions could result in required capital expenditures of approximately $1.6 billion including the amounts discussed in the previous paragraph for the AEP System. Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the preliminary estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers through regulated rates and/or future market prices for electricity where generation is deregulated, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

Superfund

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. Additional costs could be incurred to comply with new laws and regulations if enacted.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized Federal EPA to administer the clean-up programs. As of year-end 2000, subsidiaries of AEP have been named by the Federal EPA as a PRP for five sites. There are five additional sites for which AEP has received information requests which could lead to PRP designation. The Company has also been named a PRP at three sites under state law. Our 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. AEP's 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 liability is 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 are attributed to AEP in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

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, which many scientists believe are contributing to global climate change. The treaty, which requires the advice and consent of the U.S. Senate for ratification, would require the U.S. to reduce greenhouse gas emissions seven percent below 1990 levels in the years 2008-2012. Although the U.S. has agreed to the treaty and signed it on November 12, 1998, the treaty has not been submitted to the Senate for consideration as it does not contain requirements for "meaningful participation by key developing countries" and the rules, procedures, methodologies and guidelines of the treaty's emissions trading and joint implementation programs and compliance enforcement provisions have not been negotiated. At the Fourth Conference of the Parties in November 1998, the parties agreed to a work plan to complete negotiations on outstanding issues with a view toward approving them at the Sixth Conference of the Parties to be held in November 2000. During the Sixth Conference of the Parties agreement was not reached on any of the outstanding issues requiring resolution in order to faciliate ratification of the Kyoto Protocol. There are several contentious issues and literally hundreds of pages of detailed, complex rules that remain to be negotiated. Discussions are expected to resume in July 2001. While a candidate for the presidency, George Bush had stated his opposition to U.S. ratification of the Kyoto Protocol. The Seventh Conference of the Parties is scheduled for October 2001 in Morocco. AEP does not support the Kyoto Treaty as presently drafted. We will continue to work with the Administration and Congress to develop responsible public policy on this issue.

If the Kyoto treaty is approved by Congress as presently drafted, the costs for the Company to comply with the required emission reductions required by the treaty are expected to be substantial and would have a material adverse impact on results of operations, cash flows and possibly financial condition if not recovered from customers. It is management's belief that the Kyoto Protocol is unlikely to be ratified and implemented in the U.S. in its current form.

Costs for Spent Nuclear Fuel and Decommissioning

AEP, as the owner of the Cook Plant and as a partial owner of STP, has a significant future financial commitment to safely dispose of SNF and 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 the Company participates in the DOE's SNF disposal program which is described in Note 8 of the Notes to Consolidated Financial Statements. Since 1983 I&M has collected $275 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. $116 million of these funds have been deposited in external trust funds to provide for the future disposal of spent nuclear fuel and $159 million has been remitted to the DOE. CPL has collected and remitted to the DOE, $44 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 AEP 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 CPL and the other STP owners, along with a number of unaffiliated 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 the U.S. Court of Federal Claims. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary 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 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 unaffiliated 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. AEP's suit has been stayed pending further action by and permanent storage and the cost of decommissioning will continue to increase.

In January 2001, I&M and STPNOC, on behalf of STP's joint owners, joined a lawsuit against DOE, filed in November 2000 by unaffiliated utilities, related to DOE's nuclear waste fund cost recovery settlement with PECO Energy Corporation. The settlement allows PECO to skip two payments to the DOE for disposal of SNF due to the lack of progress towards development of a permanent repository for SNF. The companies believe the settlement is unlawful as the settlement would force other utilities to make up any shortfall in DOE's SNF disposal funds.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2000 estimate the cost to decommission the Cook Plant ranges from $783 million to $1,481 million in 2000 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2000, the total decommissioning trust fund balance for Cook Plant was $558 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate CPL's share of decommissioning cost to be $289 million in 1999 non-discounted dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2000, the total decommissioning trust fund for CPL's share of STP was $94 million which includes earnings on the trust investments. 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. We will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP through regulated rates and, where generation has been deregulated, through wires charges. However, AEP's future results of operations, cash flows and possibly its financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Foreign Energy Delivery, Worldwide Energy Investments and Other Business Operations

Worldwide electric and gas operations on the Consolidated Statements of Income include the foreign energy delivery, worldwide energy investments, and other segments of AEP's business. See Note 14 of the Notes to Consolidated Financial Statements for a discussion of segments.

The Company's investment in certain types of activities is limited by PUHCA. SEC authorization under PUHCA limits the Company to issuing and selling securities in an amount up to 100% of its average quarterly consolidated retained earnings balance for investment in EWGs and FUCOs. At December 31, 2000, AEP's investment in EWGs and FUCOs was $1.8 billion compared to AEP's limit of $3.4 billion by law.

SEC rules under PUHCA permit AEP to invest up to 15% of consolidated capitalization (such amount was $3.5 billion at December 31, 2000) in energy-related companies that engage in marketing and/or trading of electricity, gas and other energy commodities. The Company's gas trading business and its interests in domestic cogeneration projects are reported as investments under this rule and at December 31, 2000, the Company's investment was less than one million dollars.

The Company continues to evaluate the U.S. and inter-national energy markets for investment opportunities that complement its wholesale operations. Management expects to continue to pursue new and existing energy supply projects and to provide energy related services worldwide. Future earnings will be impacted by the performance of existing and any future investments.

The major business activities and subsidiaries of AEP's worldwide electric and gas operations are SEEBOARD, CitiPower, Yorkshire, European energy trading operations, U.S. power trading more than two transmission systems removed from the AEP transmission system and gas trading operations in the U.S., domestic and foreign generating facilities in China, Mexico and the U.S., electric distribution in South America and power plant construction. SEEBOARD's principal business is the distribution and supply of electricity in southeast England. CitiPower provides electricity and electric distribution service in the city of Melbourne, Australia. The Company owns 100% of SEEBOARD and CitiPower. The revenues and operating expenses for SEEBOARD and CitiPower are included in worldwide revenues and expenses on AEP's Consolidated Statements of Income. Interest, taxes and other nonoperating items for SEEBOARD and CitiPower are included in the appropriate income statement lines.

In 1998 SEEBOARD's 80% owned subsidiary, SEEBOARD Powerlink, signed a 30-year contract for $1.6 billion to operate, maintain, finance and renew the high-voltage power distribution network of the London Underground transportation system. SEEBOARD Powerlink will be responsible for distributing high voltage electricity to supply 270 London Underground stations and 250 miles of the rail system's track. SEEBOARD's partners in Powerlink are an international electrical engineering group and an international cable and construction group.

The Company has a 50% investment in Yorkshire, another U.K. regional electricity distribution and supply company. The investment is accounted for using the equity method of accounting with equity earnings included in other income (net) on the AEP Consolidated Statements of Income. In December 2000 the Company entered into negotiations to sell its investment in Yorkshire. On February 26, 2001, an agreement to sell the Company's 50% interest in Yorkshire was signed. The sale is expected to close by March 31, 2001. See Note 10 of the Notes to Consolidated Financial Statements.

In the U.K. all residential and commercial customers have been allowed to choose their electricity supplier since May 1999. Margins on retail electric sales have been generally declining due to competition. In April 2000 final proposals from the regulatory commission reduced distribution rates and electricity supply price caps. The distribution rate reductions and reduced price caps are expected to reduce the Company's earnings from SEEBOARD and its Yorkshire investment. In response to these final proposals and increasing competition, SEEBOARD and Yorkshire adopted an aggressive program of reducing controllable costs. Significant features of this program include staff reductions, outsourcing of certain functions and consolidation of facilities. Management intends to aggressively pursue this cost reduction program and continues to evaluate additional cost reduction measures to further mitigate the effects of the final proposals and increasing competition in the U.K. electricity supply business. Management expects that, despite the cost control measures, the rate reductions will negatively impact its earnings.

The Utilities Act which became law in the U.K. in July 2000 includes a requirement for separate licensing of electricity supply and distribution and the introduction of a prohibition of electricity supply and distribution licenses being held by the same legal entity. This requirement effectively means that the electricity supply and distribution businesses of SEEBOARD and Yorkshire must be held by separate companies. However, AEP will not be required to divest its interest in either the supply entity or the distribution entity. The separation of the supply and distribution business into two entities each for SEEBOARD and Yorkshire is not expected to have a material impact on future results of operations or cash flows.

Beginning January 1, 2001 price reductions on the supply and distribution of electricity are being implemented in Victoria, Australia. The effect of these price reductions is expected to reduce CitiPower's results of operations to the extent that they cannot be offset by reduced expenses, improved efficiencies or increased sales.

A new, higher tariff rate for the electricity from two 250 MW coal-fired generating units located in Henan Province, China was approved by the Central Chinese government in January 2000. The Company owns 70% of these units, with the remaining 30% owned by two Chinese partners. As a result of the new tariff the units contributed positively to AEP's results of operations for 2000 after incurring a loss in 1999.

Other foreign generating facilities include a 37.5% interest in 675 MW of capacity in the U.K. and a 50% interest in 118 MW of capacity in Mexico. The Company also has a 50% ownership interest in two generating plants under construction; a 600 MW facility in Mexico and a 400 MW facility in the U.K. All of these facilities sell their capacity under long-term contracts. The investment in these facilities is accounted for using the equity method.

AEP, through its CSW Energy subsidiary, has an ownership interest in seven operational domestic generation facilities in Colorado, Florida and Texas with one 440 MW facility under construction. These plants are EWGs or qualifying facilities (QF) as defined by law and not subject to cost-based rate regulation or the application of SFAS 71 regulatory accounting. The combined installed capacity of the operational facilities is 1,508 MW at December 31, 2000. The power from these QF facilities is sold under long-term power purchase agreements with the local host facility. Any merchant power is sold in the wholesale market generally under short-term contract. As a result, increases in the market price of natural gas used to generate electricity at these facilities may adversely impact results of operations.

In 1999 a 50% equity interest in one of the above facilities was sold to an unaffiliated company. The after-tax gain from the sale was approximately $33 million. An additional unit is under construction at this facility. Pursuant to the terms of the sale agreement, the unaffiliated company will make additional payments to CSW Energy upon completion of the additional unit.

Under terms of the FERC and Texas settlement agreements that approved the merger, the divestiture of certain generating units is required. The Frontera power plant, one of CSW Energy's facilities, is specifically identified as one of the plants where the entire ownership interest must be sold. On February 8, 2001, AEP announced that it had reached agreement with an unaffiliated company to sell the 500 MW Frontera power plant for $265 million in cash.

In 2000 an electricity and gas trading operation in Europe was added. This business requires minimal capital investment and offers an opportunity to employ our expertise in energy marketing and trading to a new market.

The domestic gas trading operation grew substantially in 2000 and is expected to benefit from the planned acquisition of the Houston Pipe Line Company which was announced in January 2001. The acquisition of Houston Pipe Line Company, which has more than 4,400 miles of natural gas transmission pipeline and operates one of the largest storage facilities, is expected to complement our intra-state gas transmission and storage facilities in Louisiana and extends AEP's strategy of linking physical energy asset operations with trading and marketing operations.

AEP's Louisiana gas operation is LIG, a midstream natural gas operation, that was purchased in December 1998 for approximately $340 million including working capital funds. LIG includes a fully integrated natural gas gathering, processing, storage and transportation operation in Louisiana and a gas trading and marketing operation. Assets include an intrastate pipeline system, natural gas liquids processing plants and natural gas storage facilities.

AEP's subsidiaries are engaged in the engineering and construction for third parties of three power plants in the U.S. with a capacity of 1,910 MW. These plants will be natural gas-fired facilities that are scheduled to be completed from 2001 to 2003. AEP intends to use its engineering, trading and marketing expertise on these projects some of which also include power purchase and power sale agreements to enhance its results of operations.

Financial Condition

The Cook Plant extended outage and related restart expenditures negatively affected 2000 earnings and cash flows and the write-off related to COLI and non-regulated subsidiaries further depressed earnings. Although the 2000 dividend payout ratio was 289%, it is expected that the ratio will improve significantly as a result of earnings growth in 2001. It has been a management objective to reduce the payout ratio by increasing earnings. Management expects to grow future earnings by growing the wholesale business and by controlling operations and maintenance costs.

AEP's common equity to total capitalization, including long-term debt due within one year and short-term debt, decreased from 37% in 1999 to 34% in 2000. Preferred stock at 1% remained unchanged. Long-term debt decreased from 50% to 47%, while short-term debt increased from 12% to 18%. The Company's intention is to maintain flexibility during corporate separation by issuing floating rate debt. In 2000, the Company did not issue any shares of common stock to meet the requirements of the Dividend Reinvestment and Direct Stock Purchase Plan and the Employee Savings Plan. Sales of common stock and/or equity linked securities may be necessary in the future to support the Company's plan to grow the business.

Expenditures for domestic electric utility construction are estimated to be $6 billion for the next three years. Approximately 70% of construction expenditures are expected to be financed by internally generated funds.

The year-end ratings of the subsidiaries' first mortgage bonds are listed in the following table:

Company	Moody's	S&P	Fitch
APCo	A3	A	A-
CSPCo	A3	A-	A
I&M	Baa1	A-	BBB+
KPCo	Baa1	A-	BBB+
OPCo	A3	A-	A-
CPL	A3	A-	A
PSO	A1	A	A+
SWEPCo	A1	A	A+
WTU	A2	A-	A

The ratings at the end of the year for senior unsecured debt issued by the subsidiaries are listed in the following table:

Company	Moody's	S&P	Fitch
AEP Resources*	Baa2	BBB+	BBB+
APCo	Baa1	BBB+	BBB+
CSPCo	Baa1	BBB+	A-
I&M	Baa2	BBB+	BBB
KPCo	Baa2	BBB+	BBB
OPCo	Baa1	BBB+	BBB+
CPL	Baa1	BBB+	A-
PSO	A2	BBB+	A
SWEPCo	A2	BBB+	A
WTU	A3	BBB+	—

* The rating is for a series of senior notes issued with a Support Agreement from AEP.

Financing Activity

Debt was issued in 2000 for the funding of debt maturities, for construction programs and for the growth of the wholesale business. AEP and its subsidiaries issued $1.1 billion principal amount of long-term obligations in 2000 at variable interest rates with due dates ranging from 2001 to 2007. The principal amount of long-term debt retirements, including maturities, totaled $1.6 billion with interest rates ranging from 5.25% to 9.6%.

The domestic electric utility subsidiaries generally issue short-term debt to provide for interim financing of capital expenditures that exceed internally generated funds. They periodically reduce their outstanding short-term debt through issuances of long-term debt and additional capital contributions by the parent company. The sources of funds available to the parent company, AEP, are dividends from its subsidiaries, short-term and long-term borrowings and proceeds from the issuance of common stock.

The subsidiaries formed to pursue worldwide electric and gas opportunities use short-term debt and capital contributions from the parent company for interim financing of working capital and acquisitions. Short-term debt is replaced with long-term debt when financial market conditions are favorable. Some acquisitions of existing business entities include the assumption of their outstanding debt.

The AEP System uses short-term debt, primarily commercial paper, to meet fluctuations in working capital requirements and other interim capital needs. AEP has established a system money pool to meet the short-term borrowings for certain of its subsidiaries, primarily the domestic electric utility operations. In addition, AEP also funds the short-term debt requirements of other subsidiaries that are not included in the money pool. As of December 31, 2000, AEP had back up credit facilities totaling $3.5 billion to support its commercial paper program. At December 31, 2000, AEP had $2.7 billion outstanding in short-term borrowings. The maximum amount of short-term borrowings outstanding during the year, which had a weighted average interest rate for the year of 7.5%, was $2.7 billion during December 2000.

AEP Credit purchases, without recourse, the accounts receivable of most of the domestic utility operating companies and certain non-affiliated electric utility companies. The sale of accounts receivable provides the domestic electric utility operating companies with cash immediately, thereby reducing working capital needs and revenue requirements. In addition, AEP Credit's capital structure contains greater leverage than that of the domestic electric utility operating companies, so cost of capital is lowered. AEP Credit issues commercial paper to meet its financing needs. At December 31, 2000, AEP Credit had a $2.0 billion unsecured back up credit facility to support its commercial paper program, which had $1.2 billion outstanding. The maximum amount of such commercial paper outstanding during the year, which had a weighted average interest rate of 6.6%, was $1.5 billion during September 2000.

Market Risks

The Company as a major power producer and a trader of wholesale electricity and natural gas has certain market risks inherent in its business activities. The trading of electricity and natural gas and related financial derivative instruments exposes the Company to market risk. Market risk represents the risk of loss that may impact the Company due to changes in commodity market prices and rates. Policies and procedures have been established to identify, assess, and manage market risk exposures including the use of a risk measurement model which calculates Value at Risk (VaR). The VaR is based on the variance - covariance method using historical prices to estimate volatilities and correlations and assuming a 95% confidence level and a one-day holding period. Throughout the year ending December 31, 2000 the average, high, and low VaRs in the wholesale electricity and gas trading portfolio were $10 million, $32 million, and $1 million, respectively. The average, high, and low VaRs for the year ending December 31, 1999 was $4 million, $8 million, and $1 million, respectively. Based on this VaR analysis, at December 31, 2000 a near term typical change in commodity prices is not expected to have a material effect on the Company's results of operations, cash flows or financial condition.

Investments in foreign ventures expose the Company to risk of foreign currency fluctuations. The Company's exposure to changes in foreign currency exchange rates related to these foreign ventures and investments is not expected to be significant for the foreseeable future.

The Company is exposed to changes in interest rates primarily due to short-and long-term borrowings to fund its business operations. The Company measures interest rate market risk exposure utilizing a VaR model. 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 weekly prices. The risk of potential loss in fair value attributable to the Company's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $998 million at December 31, 2000 and $966 million at December 31, 1999. The Company would not expect to liquidate its entire debt portfolio in a one year holding period. Therefore, a near term change in interest rates should not materially affect results of operations or the consolidated financial position of the Company. The Company is currently utilizing interest rate swaps as a hedge to manage its exposure to interest rate fluctuations in the U.K. and Australia.

The Company has investments in debt and equity securities which are held in nuclear trust funds. The trust investments and their fair value are discussed in Note 15 of the Notes to Consolidated Financial Statements. Instruments in the trust funds have not been included in the market risk calculation for interest rates as these instruments are marked-to-market and changes in market value are reflected in a corresponding decommissioning liability. Any differences between the trust fund assets and the ultimate liability should be recoverable from ratepayers.

Inflation affects AEP's cost of replacing utility plant and the cost of operating and maintaining its plant. The rate-making process limits recovery to the historical cost of assets, resulting in economic losses when the effects of inflation are not recovered from customers on a timely basis. However, economic gains that result from the repayment of long-term debt with inflated dollars partly offset such losses.

<u>Other Matters</u>

New Accounting Standards — SFAS 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS 137 and SFAS 138, is effective for the AEP System beginning January 1, 2001. SFAS 133 requires that entities recognize all derivatives as either assets or liabilities and measure them at fair value. Changes in the fair value of derivative assets and liabilities must be recognized currently in net income. Changes in the derivatives that are effective cash flow hedges are recorded in other comprehensive income.

Pending the resolution of certain industry issues presently before the FASB's Derivatives Implementation Group (DIG), the effect of adoption of SFAS 133 will result in transition adjustment amounts which will have an immaterial effect on both net income and other comprehensive income.

The FASB's DIG, has issued tentative guidance, which has not yet been approved by the FASB, that option contracts cannot qualify as normal purchases and sales. In addition there are two industry issues pending resolution by the DIG related to whether electric capacity contracts that may have some characteristics of purchased and written options can qualify as normal sales, and whether contracts which do not result in physical delivery of power because of transmission constraints are derivatives.

While the Company believes the majority of the its fuel supply agreements should qualify as normal purchases and that the majority of its power sales agreements qualify as normal sales, the ultimate resolution of the above issues may result in accounting for certain power sales and fuel supply agreements as derivatives which may have a material effect on reported net income under SFAS 133. Whether the impact will be favorable or adverse will depend on the market prices compared to the contractual prices at the time of valuation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
(in millions - except per share amounts)

	Year Ended December 31,		
	2000	1999	1998
REVENUES:			
Domestic Electric Utility Operations	$10,827	$ 9,838	$ 9,834
Worldwide Electric and Gas Operations	2,867	2,569	2,006
TOTAL REVENUES	13,694	12,407	11,840
EXPENSES:			
Fuel and Purchased Power	4,128	3,449	3,455
Maintenance and Other Operation	3,017	2,675	2,596
Non-recoverable Merger Costs	203	—	—
Depreciation and Amortization	1,062	1,011	989
Taxes Other Than Income Taxes	671	664	659
Worldwide Electric and Gas Operations	2,587	2,283	1,861
TOTAL EXPENSES	11,668	10,082	9,560
OPERATING INCOME	2,026	2,325	2,280
OTHER INCOME (net)	33	139	95
INCOME BEFORE INTEREST, PREFERRED DIVIDENDS AND INCOME TAXES	2,059	2,464	2,375
INTEREST AND PREFERRED DIVIDENDS	1,160	996	898
INCOME BEFORE INCOME TAXES	899	1,468	1,477
INCOME TAXES	597	482	502
INCOME BEFORE EXTRAORDINARY ITEM	302	986	975
EXTRAORDINARY LOSSES:			
DISCONTINUANCE OF REGULATORY ACCOUNTING FOR GENERATION	(35)	(8)	—
LOSS ON REACQUIRED DEBT	—	(6)	—
NET INCOME	$267	$972	$975

AVERAGE NUMBER OF SHARES OUTSTANDING	322	321	318
EARNINGS PER SHARE:			
Income Before Extraordinary Item	$ 0.94	$3.07	$3.06
Extraordinary Losses	(0.11)	(.04)	—
Net Income	$ 0.83	$3.03	$3.06
CASH DIVIDENDS PAID PER SHARE	$ 2.40	$2.40	$2.40

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(in millions - except share data)

	December 31,	
	2000	1999
ASSETS		
CURRENT ASSETS:		
Cash and Cash Equivalents	$437	$609
Special Deposits	—	50
Accounts Receivable:		
Customers	827	553
Miscellaneous	2,883	1,486
Allowance for Uncollectible Accounts	(11)	(12)
Energy Trading Contracts	16,627	1,001
Other	1,268	1,311
TOTAL CURRENT ASSETS	22,031	4,998
PROPERTY PLANT AND EQUIPMENT:		
Electric:		
Production	16,328	15,869
Transmission	5,609	5,495
Distribution	10,843	10,432
Other (including gas and coal mining assets and nuclear fuel)	4,077	4,081
Construction Work in Progress	1,231	1,061
Total Property, Plant and Equipment	38,088	36,938
Accumulated Depreciation and Amortization	15,695	15,073
NET PROPERTY, PLANT AND EQUIPMENT	22,393	21,865

REGULATORY ASSETS	3,698	3,464
INVESTMENTS IN POWER AND COMMUNICATIONS PROJECTS	782	862
GOODWILL (NET OF AMORTIZATION)	1,382	1,531
LONG-TERM ENERGY TRADING CONTRACTS	1,620	136
OTHER ASSETS	2,642	2,863
TOTAL	$54,548	$35,719

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2000	1999
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts Payable	$ 2,627	$ 1,280
Short-term Debt	4,333	3,012
Long-term Debt Due Within One Year*	1,152	1,367
Energy Trading Contracts	16,801	964
Other	2,154	1,443
TOTAL CURRENT LIABILITIES	27,067	8,066
LONG-TERM DEBT*	9,602	10,157
CERTAIN SUBSIDIARY OBLIGATED, MANDATORILY REDEEMABLE, PREFERRED SECURITIES OF SUBSIDIARY TRUSTS HOLDING SOLELY JUNIOR SUBORDINATED DEBENTURES OF SUCH SUBSIDIARIES	334	335
DEFERRED INCOME TAXES	4,875	5,150
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	203	213
DEFERRED INVESTMENT TAX CREDITS	528	580
LONG-TERM ENERGY TRADING CONTRACTS	1,381	108
DEFERRED CREDITS AND REGULATORY LIABILITIES	637	607
OTHER NONCURRENT LIABILITIES	1,706	1,648

CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES*			161	182
COMMITMENTS AND CONTINGENCIES (Note 8)				
COMMON SHAREHOLDERS' EQUITY:				
Common Stock-Par Value $6.50:				
	2000	1999		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	331,019,146	330,692,317		
(8,999,992 shares were held in treasury at December 31, 2000 and 1999)			2,152	2,149
Paid-in Capital			2,915	2,898
Accumulated Other Comprehensive Income (Loss)			(103)	(4)
Retained Earnings			3,090	3,630
TOTAL COMMON SHAREHOLDERS' EQUITY			8,054	8,673
TOTAL			$54,548	$35,719

* See Accompanying Schedules.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2000	1999	1998
OPERATING ACTIVITIES:			
Net Income	$267	$972	$975
Adjustments for Noncash Items:			
Depreciation and Amortization	1,299	1,294	1,171
Deferred Federal Income Taxes	(170)	180	(2)
Deferred Investment Tax Credits	(36)	(38)	(37)
Amortization (Deferral) of Operating Expenses and Carrying Charges (net)	48	(151)	15
Equity in Earnings of Yorkshire Electricity Group plc	(44)	(45)	(38)
Extraordinary Item	35	14	—
Deferred Costs Under Fuel Clause Mechanisms	(449)	(191)	36
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(1,632)	(80)	(329)
Fuel, Materials and Supplies	147	(162)	(23)
Accrued Utility Revenues	(79)	(35)	5

Accounts Payable	1,322	74	270
Taxes Accrued	172	29	20
Payment of Disputed Tax and Interest Related to COLI	319	(16)	(303)
Other (net)	304	(231)	195
Net Cash Flows From Operating Activities	1,503	1,614	1,955
INVESTING ACTIVITIES:			
Construction Expenditures	(1,773)	(1,680)	(1,396)
Investment in CitiPower	—	—	(1,054)
Investment in Gas Assets	—	—	(340)
Other	19	7	(54)
Net Cash Flows Used For Investing Activities	(1,754)	(1,673)	(2,844)
FINANCING ACTIVITIES:			
Issuance of Common Stock	14	93	96
Issuance of Long-term Debt	1,124	1,391	2,645
Retirement of Cumulative Preferred Stock	(20)	(170)	(28)
Retirement of Long-term Debt	(1,565)	(915)	(1,101)
Change in Short-term Debt (net)	1,308	812	264
Dividends Paid on Common Stock	(805)	(833)	(827)
Other Financing Activities	—	(43)	—
Net Cash Flows From Financing Activities	56	335	1,049
Effect of Exchange Rate Change on Cash	23	(2)	—
Net Increase (Decrease) in Cash and Cash Equivalents	(172)	274	160
Cash and Cash Equivalents January 1	609	335	175
Cash and Cash Equivalents December 31	$437	$609	$335

See Notes to Consolidated Financial Statements.

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

	Common Shares	Stock Amount	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 1998	326	$2,036	$2,818	$3,356	$23	$8,233
Conforming Change in Accounting Policy	—	—	—	(13)	—	(13)

Reclassification Adjustment	—	85	(85)	—	—	—
Adjusted Balance at Beginning of Period	326	2,121	2,733	3,343	23	8,220
Issuances	2	13	83	—	—	96
Retirements and Other	—	—	2	3	—	5
Cash Dividends Declared	—	—	—	(827)	—	(827)
						7,494
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	—	—	—	—	6	6
Unrealized Loss on Securities	—	—	—	—	(14)	(14)
Adjustments for Gain Included in Net Income	—	—	—	—	(7)	(7)
Minimum Pension Liability	—	—	—	—	(1)	(1)
Net Income	—	—	—	975	—	975
Total Comprehensive Income						959
DECEMBER 31, 1998	328	2,134	2,818	3,494	7	8,453
Conforming Change in Accounting Policy	—	—	—	(1)	—	(1)
Adjusted Balance at Beginning of Period	328	2,134	2,818	3,493	7	8,452
Issuances	3	15	77	—	—	92
Retirements and Other	—	—	3	—	—	3
Cash Dividends Declared	—	—	—	(833)	—	(833)
						7,714
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	—	—	—	—	(13)	(13)
Minimum Pension Liability	—	—	—	—	2	2
Net Income	—	—	—	972	—	972
Total Comprehensive Income						961
DECEMBER 31, 1999	331	2,149	2,898	3,632	(4)	8,675
Conforming Change in Accounting Policy	—	—	—	(2)	—	(2)

Adjusted Balance at Beginning of Period	331	2,149	2,898	3,630	(4)	8,673
Issuances	—	3	11	—	—	14
Cash Dividends Declared	—	—	—	(805)	—	(805)
Other	—	—	6	(2)	—	4
						7,886
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	—	—	—	—	(119)	(119)
Reclassification Adjustment						
For Loss Included in Net Income	—	—	—	—	20	20
Net Income	—	—	—	267		267
Total Comprehensive Income						168
DECEMBER 31, 2000	331	$2,152	$2,915	$3,090	$(103)	$8,054

See Notes to Consolidated Financial Statements.

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

1. Significant Accounting Policies:

Business Operations — AEP's principal business conducted by its 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 follow the Uniform System of Accounts prescribed by FERC. They are subject to further regulation with regard to rates and other matters by state regulatory commissions.

Wholesale marketing and trading of electricity and gas is conducted in the United States and Europe. In addition the Company's domestic operations includes non-regulated independent power and cogeneration facilities and an intra-state midstream natural gas operation in Louisiana.

International operations include regulated supply and distribution of electricity and other non-regulated power generation projects in the United Kingdom, Australia, Mexico, South America and China.

In addition to the above energy related operations, the Company is also involved in domestic factoring of accounts receivable, investing in leveraged leases and providing energy services worldwide and communications related services domestically.

Rate Regulation — The AEP System is subject to regulation by the SEC under the PUHCA. The rates charged by the domestic utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail generation and distribution rates. The prices charged by foreign subsidiaries located in the UK, Australia, China, Mexico and Brazil are regulated by the authorities of that country generally subject to price controls.

Principles of Consolidation — The consolidated financial statements include AEP Co., Inc. and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation. Equity investments that are 50% or less owned are accounted for using the equity method with their equity earnings included in Other Income, net.

Basis of Accounting — As the owner of cost-based rate-regulated electric public utility companies, AEP Co., Inc.'s 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 (deferred revenue) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues. Application of SFAS 71 for the generation portion of the business was discontinued as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by CPL, WTU, and SWEPCo in September 1999 and in Arkansas by SWEPCo in September 1999. See Note 7, Industry Restructuring for additional information.

Use of Estimates — The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of estimates and assumptions that affect the reported amounts of assets and liabilities along with the disclosure of contingent liabilities at the date of financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Property, Plant and Equipment — Domestic electric utility property, plant and equipment are stated at original cost of the acquirer. The property, plant and equipment of SEEBOARD, CitiPower and LIG are stated at their fair market value at acquisition 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 deducted from accumulated depreciation. The costs of labor, materials and overheads incurred to operate and maintain plant are included in operating expenses.

Allowance for Funds Used During Construction (AFUDC) — AFUDC is a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For domestic regulated electric utility plant, it represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 2000, 1999 and 1998 were not significant. Effective with the discontinuance of the application of SFAS 71 regulatory accounting for domestic generating assets in Arkansas, Ohio, Texas, Virginia and West Virginia and for worldwide operations interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." The amounts of interest capitalized was not material in 2000, 1999, and 1998.

Depreciation, Depletion and Amortization — Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of property, other than coal-mining property, and is calculated largely through the use of composite rates by functional class as follows:

Functional Class of Property	Annual Composite Depreciation Rates Ranges
	2000
Production:	
Steam-Nuclear	2.8% to 3.4%
Steam-Fossil-Fired	2.3% to 4.5%
Hydroelectric-Conventional and Pumped Storage	2.7% to 3.4%
Transmission	1.7% to 3.1%
Distribution	3.3% to 4.2%
Other	2.5% to 20.0%

Functional Class of Property	Annual Composite Depreciation Rates Ranges
	1999
Production:	
Steam-Nuclear	2.8% to 3.4%
Steam-Fossil-Fired	3.2% to 5.0%
Hydroelectric-Conventional and Pumped Storage	2.7% to 3.4%
Transmission	1.7% to 2.7%
Distribution	2.8% to 4.2%
Other	2.0% to 20.0%

Functional Class of Property	Annual Composite Depreciation Rates Ranges
	1998
Production:	
Steam-Nuclear	2.8% to 3.4%
Steam-Fossil-Fired	3.2% to 4.4%
Hydroelectric-Conventional and Pumped Storage	2.7% to 3.4%
Transmission	1.7% to 2.7%
Distribution	3.3% to 4.2%
Other	2.5% to 20.0%

Depreciation, depletion and amortization of coal-mining assets is provided over each asset's estimated useful life or the estimated life of the mine, whichever is shorter, and is calculated using the straight-line method for mining structures and equipment. The units-of-production method is used to amortize coal rights and mine development costs based on estimated recoverable tonnages at a current average rate of $5.07 per ton in 2000, $2.32 per ton in 1999 and $1.85 per ton in 1998. These costs are included in the cost of coal charged to fuel expense. See Note 5 "Rate Matters" regarding the closure and possible sale of affiliated mines.

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

Inventory — Except for CPL, PSO and WTU, the domestic utility companies value fossil fuel inventories using a weighted average cost method. CPL, PSO and WTU, utilize the LIFO method to value fossil fuel inventories. SWEPCo continues to use the weighted average cost method pending approval of its request to the Arkansas Commission to utilize the LIFO method. Natural gas inventories are marked-to-market.

Accounts Receivable — AEP Credit Inc. (formerly CSW Credit) factors accounts receivable for the domestic utility subsidiaries and unaffiliated companies.

Foreign Currency Translation — The financial statements of subsidiaries outside the U.S. which are included in AEP's consolidated financial statements are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52 "Foreign Currency Translation". Assets and liabilities are translated to U.S. dollars at year-end rates of exchange and revenues and expenses are translated at monthly average exchange rates throughout the year. Currency translation gain and loss adjustments are recorded in shareholders' equity as "Accumulated Other Comprehensive Income (Loss)". The non-cash impact of the changes in exchange rates on cash, resulting from the translation of items at different exchange rates is shown on AEP's Consolidated Statement of Cash Flows in "Effect of Exchange Rate Change on Cash." Actual currency transaction gains and losses are recorded in income.

Energy Marketing and Trading Transactions — The Company engages in wholesale electricity and natural gas marketing and trading transactions (trading activities). Trading activities involve the sale of energy under physical forward contracts at fixed and variable prices and the trading of energy contracts including exchange traded futures and options, over-the-counter options and swaps. The majority of these transactions represent physical forward electricity contracts in the Company's traditional marketing area and are typically settled by entering into offsetting contracts. The net revenues from these transactions in the Company's traditional marketing area are included in regulated revenues for ratemaking, accounting and financial and regulatory reporting purposes.

The Company also purchases and sells electricity and gas options, futures and swaps, and enters into forward purchase and sale contracts for electricity outside its traditional marketing area and gas. These transactions represent non-regulated trading activities that are included in revenues from worldwide electric and gas operations.

The Company follows EITF 98-10 and EITF 00-17, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" and "Measuring the Fair Value of Energy-Related Contracts in Applying Issue 98-10", respectively. EITF 98-10 requires that all energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market in the Company's regulated jurisdictions are deferred as regulatory assets or liabilities for those open electricity trading transactions within the Company's marketing area that are included in cost of service on a settlement basis for ratemaking purposes. Non-regulated jurisdictions with open electricity trading transactions within the Company's marketing area are marked-to-market and included in domestic electric utility operations revenues. Non-regulated and regulated jurisdictions open electricity trading contracts are accounted for on a mark-to-market basis and included in worldwide electric and gas operations revenues. Open gas trading contracts are accounted for on a mark-to-market basis and included in worldwide electric and gas operations. Unrealized mark-to-market gains and losses from all trading activity are reported as assets and liabilities, respectively.

Hedging and Related Activities — In order to mitigate the risks of market price and interest rate fluctuations, the Company's foreign subsidiaries, SEEBOARD and CitiPower, utilize interest swaps, currency swaps and forward contracts to hedge such market fluctuations. Changes in the market value of these swaps and contracts are deferred until the gain or loss is realized on the underlying hedged asset, liability or commodity. To qualify as a hedge, these transactions must be designated as a hedge and changes in their fair value must correlate with changes in the price and interest rate movement of the underlying asset, liability or commodity. This in effect reduces the Company's exposure to the effects of market fluctuations related to price and interest rates.

The Company enters into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory debt instruments are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses from these transactions are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 2000 or 1999. See Note 15 — "Financial Instruments, Credit and Risk Management" for further discussion of the accounting for risk management transactions.

Revenues and Fuel Costs — Domestic revenues include the accrual of service provided but unbilled at month-end as well as billed revenues. The cost of fuel consumed is charged to expense as incurred. Where applicable under governing regulatory commission retail rate orders, any resulting fuel cost over or under-recoveries are deferred as regulatory liabilities or regulatory assets in accordance with SFAS 71. These deferrals generally are billed or refunded to customers in later months with the regulator's review and approval. Wholesale jurisdictional fuel cost increases and decreases over amounts included in base rates are expensed and billed as incurred. See Note 5 "Rate Matters" and Note 7 "Industry Restructuring" for further information about fuel recovery.

Levelization of Nuclear Refueling Outage Costs — In order to match costs with regulated revenues, which include outage costs on a normalized basis, 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 commencement of an outage and ending with the beginning of the next outage.

Amortization of Cook Plant Deferred Restart Costs — Pursuant to settlement agreements approved by the IURC and the MPSC to resolve all issues related to an extended outage of the Cook Plant, I&M deferred $200 million of incremental operation and maintenance costs during 1999. The deferred amount is being amortized to expense on a straight-line basis over five years from January 1, 1999 to December 31, 2003. I&M amortized $40 million in 1999 and 2000, leaving $120 million as an SFAS 71 regulatory asset at December 31, 2000 on the Consolidated Balance Sheets of AEP and I&M.

Income Taxes — The AEP System follows the liability method of accounting for income taxes as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence. Where the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, 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 in accordance with SFAS 71 to match the regulated revenues and tax expense.

Investment Tax Credits — 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.

Debt and Preferred Stock — Where appropriate gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment. If the debt is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost based regulatory accounting under SFAS 71 are generally deferred and amortized over the term of the replacement debt commensurate with their recovery in rates. Gains and losses on the reacquisition of debt for operations not subject to SFAS 71 are reported as a component of net income.

Debt discount or premium and debt issuances expenses are deferred and amortized over the term of the related debt, with the amortization included in interest charges.

Where rates are regulated redemption premiums paid to reacquire preferred stock of the 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 amortized to retained earnings consistent with the timing of its recovery in rates in accordance with SFAS 71.

Goodwill — The amount of acquisition cost in excess of the fair value allocated to tangible assets obtained through an acquisition accounted for as a purchase combination is recorded as goodwill. Amortization of goodwill is on a straight-line basis generally over 40 years except for the portion of goodwill associated with gas trading and marketing activities which is being amortized on a straight-line basis over 10 years. The recoverability of goodwill (evaluated on undiscounted operating cash flow analysis) is reviewed when events or changes in circumstances indicate that the carrying amount may exceed fair value.

Other Assets — Other assets are comprised primarily of nuclear decommissioning and spent nuclear fuel disposal trust funds and licenses for CitiPower operating franchises. Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Other Assets at market value in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Under the provisions of SFAS 71, unrealized gains and losses from securities in these trust funds are not reported in equity but result in adjustments to the 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 — Comprehensive income is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners.

Components of Other Comprehensive Income — The following table provides the components that comprise the balance sheet amount in Accumulated Other Comprehensive Income for AEP.

	December 31,		
Components	2000	1999	1998
		(millions)	
Foreign Currency Adjustments	$ (99)	$ 20	$ 33

Unrealized Losses on Securities	—	(20)	(20)
Minimum Pension Liability	(4)	(4)	(6)
	$(103)	$ (4)	$7

Segment Reporting — The Company has adopted SFAS No. 131, which requires disclosure of selected financial information by business segment as viewed by the chief operating decision-maker. See Note 14 "Business Segments" for further discussion and details regarding segments.

Common Stock Options — AEP follows Accounting Principles Board Opinion 25 to account for stock options. Compensation expense is not recognized at the date of grant, because the exercise price of stock options awarded under the stock option plan equals the market price of the underlying stock on the date of grant.

EPS — Basic earnings per share is determined based upon the weighted average number of common shares outstanding during the years presented. Diluted earnings per share is based upon the weighted average number of common shares and stock options outstanding during the years presented. Basic and diluted are the same in 2000, 1999 and 1998.

Reclassification — Certain prior year financial statement items have been reclassified to conform to current year presentation. Such reclassification had no impact on previously reported net income.

2. Extraordinary Items:

Extraordinary Items — Extraordinary items were recorded for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of the business in the Ohio, Virginia, West Virginia, Texas and Arkansas state jurisdictions. See Note 7 "Industry Restructuring" for descriptions of the restructuring plans and related accounting effects. The following table shows the components of the extraordinary items reported on the consolidated statements of income:

	Year Ended December 31,	
	2000	1999
	(in millions)	
Extraordinary Items:		
Discontinuance of Regulatory Accounting for Generation:		
Ohio Jurisdiction (Net of Tax of $35 Million)	$(44)	$—
Virginia and West Virginia Jurisdictions (Inclusive of Tax Benefit of $8 Million)	9	—
Texas and Arkansas Jurisdictions (Net of Tax of $5 Million)	—	(8)
Loss on Reacquired Debt (Net of Tax of $3 Million)	—	(6)
Extraordinary Items	$(35)	$(14)

There were no extraordinary items in 1998.

3. Merger:

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. Under the terms of the merger agreement, approximately 127.9 million shares of AEP Common Stock were issued in exchange for all the outstanding shares of CSW Common Stock based upon an exchange ratio of 0.6 share of AEP Common Stock for each share of CSW Common Stock. Following the exchange, former shareholders of AEP owned approximately 61.4 percent of the corporation, while former CSW shareholders owned approximately 38.6 percent of the corporation.

The merger was accounted for as a pooling of interests. Accordingly, AEP's consolidated financial statements give retroactive effect to the merger, with all periods presented as if AEP and CSW had always been combined. Certain reclassifications have been made to conform the historical financial statement presentation of AEP and CSW.

The following table sets forth revenues, extraordinary items and net income previously reported by AEP and CSW and the combined amounts shown in the accompanying financial statements for 1999 and 1998:

	Year Ended December 31,	
	1999	1998
	(in millions)	
Revenues:		
AEP	$ 6,870	$ 6,358
CSW	5,537	5,482
AEP After Pooling	$12,407	$11,840
Extraordinary Items:		
AEP	$—	$—
CSW	(14)	—
AEP After Pooling	$(14)	$—
Net Income:		
AEP	$520	$536
CSW	455	440
Conforming Adjustment	(3)	(1)
AEP After Pooling	$972	$975

The combined financial statements include an adjustment to conform CSW's accounting for vacation pay accruals with AEP's accounting. The effect of the conforming adjustment was to reduce net assets by $16 million at December 31, 1999 and reduce net income by $3 million and $1 million for the years ended December 31, 1999 and 1998, respectively.

In connection with the merger, $203 million ($180 million after tax) of non-recoverable merger costs were expensed through December 31, 2000. Such costs included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were non-recoverable change in control payments. Merger transaction and transition costs of $45 million 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 ($4 million for the year 2000) included in depreciation and amortization expense. Merger transition costs are expected to continue to be incurred for several years after the merger and will be expensed or deferred for amortization as appropriate. 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 beginning in the third quarter of 2000.

In connection with the merger, the PUCT approved a settlement agreement that provides for, among other things, sharing net merger savings with Texas customers of CPL, SWEPCo and WTU over six years after consummation of the merger through rate reduction riders. The settlement agreement results in rate reductions for Texas customers totaling $221 million over a six-year period commencing with the merger's consummation. The rate reduction was composed of $84 million of net merger savings and $137 million to resolve issues associated with CPL's, SWEPCo's and WTU's rate and fuel reconciliation proceedings in Texas. Under the terms of the settlement agreement, base rates cannot be increased until three years after consummation of the merger.

The IURC and MPSC approved merger settlement agreements that, among other things, provide for sharing net merger savings with I&M's retail customers over eight years through reductions to customers' bills. The terms of the Indiana settlement require reductions in customers' bills of approximately $67 million over eight years. Under the Michigan settlement, billing credits will be used to reduce customers' bills by approximately $14 million over eight years for net guaranteed merger savings. The Indiana settlement extends the base rate freeze in the Cook Plant extended outage settlement agreement until January 1, 2005 and requires additional annual deposits of $6 million to the nuclear decommissioning trust fund for the Indiana jurisdiction for the years 2001 through 2003. As a result of an appeal of the Indiana settlement agreement by a consumer group, I&M has not reflected the reductions in Indiana jurisdictional customers' bills. Instead, pending the result of the appeal, I&M recorded a liability ($1 million at December 31, 2000) for the reduction due to its Indiana customers under the settlement.

The KPSC approved a settlement agreement that, among other things, provides for sharing net merger savings with KPCo's customers over eight years through reductions to customers' bills and prohibits a general increase in base rates or other charges for three years following consummation of the merger. The Kentucky customers' share of the net merger savings is expected to be approximately $28 million.

A merger settlement agreement for PSO was approved by the Oklahoma Corporation Commission that, among other things, provides for sharing approximately $28 million in guaranteed net merger savings over five years with Oklahoma customers, prohibits an increase in Oklahoma base rates prior to January 1, 2003 and requires an application to join an RTO be filed with FERC by December 31, 2001.

The Arkansas Public Service Commission approved an agreement related to the merger which, among other things, provides for $6 million of net merger savings to reduce SWEPCo customers rates over five years in Arkansas and prohibits a base rate increase being effective prior to January 1, 2002.

SWEPCo's Louisiana customers will receive approximately $18 million of merger savings over eight years according to a merger approval order issued by the Louisiana Public Service Commission. In addition, the order capped base rates for five years after the consummation of the merger (until June 2005) and required that benefits from off-system sales be shared with ratepayers.

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.

Most of the merger settlement agreements approved by the regulatory commissions require the AEP System electric companies to join regional transmission organizations. AEP and several other unaffiliated utilities formed the Alliance RTO before the consummation of the merger. As a condition of FERC's approval of the merger, the former CSW electric operating companies were required to join an RTO prior to December 31, 2000 and to transfer the operation and control of their transmission facilities to that RTO by December 15, 2001. The former CSW operating companies are members of ERCOT or SPP which are transmission pooling organizations in certain geographic areas of the U.S. whose goals include enhancement of bulk electric transmission reliability. The SPP has filed with FERC to be approved as an RTO. Due to the FERC's inaction on approving the SPP RTO, in December 2000 the AEP operating companies in the SPP service area filed with the FERC requesting an extension of time to join an RTO until 75 days following the FERC's approval of an RTO for the SPP service area. Initial filings to gain FERC approval for the Alliance RTO were made and conditional approval was granted by the FERC. The Alliance RTO made compliance filings as requested by the FERC and these were accepted in January 2001. Final FERC approval of the SPP RTO is pending.

The divestiture of 1,904 MW of generating capacity was required as a condition of regulatory approval of the merger by the FERC and PUCT. Under the FERC-approved merger agreement the divestiture of 550 MW of generating capacity comprised of 300 MW of capacity in SPP and 250 MW of capacity in ERCOT is required. The FERC is requiring AEP and CSW to divest their entire ownership interest in and operational control of the entire generating facilities that produce the capacity to be divested. The FERC required divestiture of the identified ERCOT capacity must be completed by March 15, 2001 and for the SPP capacity by July 1, 2002. The FERC found that certain energy sales in SPP and ERCOT would be a reasonable and effective interim mitigation measure until the required SPP and ERCOT divestitures could be completed. In February 2001, AEP announced the sale of Frontera, one of the plants required to be divested by the settlement agreements approved by the FERC. The Texas settlement calls for the divestiture of a total of 1,604 MW of generating capacity within Texas inclusive of 250 MW ordered to be divested by FERC. The Texas divestiture cannot proceed until two years after the merger closes to satisfy the requirements to use pooling-of-interests accounting treatment. The FERC divestiture is not limited by the pooling rules because it is regulatory ordered.

The current annual dividend rate per share of AEP common stock is $2.40. The dividends per share reported on the statements of income for prior periods represent pro forma amounts and are based on AEP's historical annual dividend rate of $2.40 per share. If the dividends per share reported for prior periods were based on the sum of the historical dividends declared by AEP and CSW, the annual dividend rate would be $2.60 per combined share for the years ended December 31, 1999 and 1998.

4. Nuclear Plant Restart:

The restart of both units of the Cook Plant was completed with Unit 2 reaching 100% power on July 5, 2000 and Unit 1 achieving 100% power on January 3, 2001. Cook Plant is a 2,110 MW two-unit plant owned and operated by I&M under licenses granted by the NRC. I&M shut down both units of the Cook Plant in September 1997 due to questions regarding the operability of certain safety systems that arose during a NRC architect engineer design inspection.

Settlement agreements in the Indiana and Michigan retail jurisdictions that address recovery of Cook Plant related outage costs were approved in 1999. The IURC approved a settlement agreement in March 1999 that resolved all matters related to the recovery of replacement energy fuel costs and all outage/restart costs and related issues during the extended outage of the Cook Plant. The settlement agreement provides for, among other things, the deferral of unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999; the deferral of up to $150 million of restart related nuclear operation and maintenance costs in 1999 above the amount included in base rates; the amortization of the deferred fuel revenues and non-fuel operation and maintenance cost deferrals over a five-year period ending December 31, 2003; a freeze in base rates through December 31, 2003; and a fixed fuel recovery charge through March 1, 2004. The regulatory approved deferrals were recorded in 1999 as a regulatory asset in accordance with SFAS 71.

In December 1999 the MPSC approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases that resolved all issues related to the Cook Plant extended outage. The settlement agreement limits I&M's ability to increase base rates and freezes the power supply cost recovery factor until January 1, 2004; permits the deferral of up to $50 million in 1999 of jurisdictional non-fuel nuclear operation and maintenance expenses; authorizes the amortization of power supply cost recovery revenues accrued from September 9, 1997 to December 31, 1999 and non-fuel nuclear operation and maintenance cost deferrals over a five-year period ending December 31, 2003. The regulatory approved deferrals were recorded in the fourth quarter of 1999.

The amounts of restart costs charged to other operation and maintenance expenses were as follows:

	Year Ended December 31,		
	2000	1999	1998
Costs Incurred	$297	$ 289	$78
Deferred Pursuant to Settlement Agreements	—	(200)	—
Amortization of Deferrals	40	40	—
Charged to O&M Expense	$337	$ 129	$78

At December 31, 2000 and 1999, deferred restart costs of $120 million and $160 million, respectively, remained as regulatory assets to be amortized through 2003. Also pursuant to the settlement agreements, accrued fuel-related revenues of $38 million and $37 million in 2000 and 1999, respectively, were amortized. At December 31, 2000 and 1999, fuel-related revenues of $113 million and $150 million, respectively, were included in regulatory assets and will be amortized through December 31, 2003 for both jurisdictions.

The amortization of restart costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements will adversely affect results of operations through December 31, 2003 when the amortization period ends. The annual amortization of restart cost and fuel-related revenue deferrals is $78 million.

5. Rate Matters:

Texas Jurisdictional Fuel Filings — AEP's Texas electric operating companies have been experiencing significant natural gas fuel price increases which have resulted in under-recoveries of fuel costs and the need to seek increases in fuel rates and surcharges to recover these under-recoveries.

CPL Fuel Filings — In July 2000 CPL filed with the PUCT an application to implement an increase in fuel factor revenues effective with the September 2000 billing month. Additionally, CPL proposed to implement an interim fuel surcharge to collect its under-recovered fuel costs, including accumulated interest, over a twelve-month period beginning in October 2000.

In September 2000 the PUCT approved a settlement. The settlement provided for an increase in fuel factor revenues of $173.5 million annually and provided for a two-phase surcharge totaling $86.4 million. The recovery of the first phase surcharge of $21.3 million for previously under-recovered fuel costs including accumulated interest for the period from December 1, 1999 through May 31, 2000 was authorized to be collected in September through December 2000. The second surcharge was not to exceed $65.1 million for projected under-recoveries for the period from June 2000 through August 2000 and was authorized to be collected January through September 2001. A September 2000 compliance filing showed the actual under-recovery for June 2000 through August 2000 to be $93.7 million. The remaining under-recovery amount of $28.6 was carried forward into a January 2001 filing.

In January 2001 CPL filed with the PUCT an application to implement an increase in fuel factors of $175.9 million, effective with the March 2001 billing month over the ten months March 2001 through December 2001. Additionally, CPL proposed to implement an interim fuel surcharge of $51.8 million, including accumulated interest, over a nine-month period beginning in April 2001 to collect its under-recovered fuel costs. Approval by the PUCT is pending.

SWEPCo Fuel Filings — In November 2000 SWEPCo filed with the PUCT an application for authority to implement an increase in fuel factor revenues effective with the January 2001 billing month. SWEPCo also proposed to implement an interim fuel surcharge to collect its under-recovered fuel costs, including accumulated interest, over a six-month period beginning in January 2001.

In January 2001 the PUCT approved SWEPCo's application. The order allows an increase in fuel factors of $12 million on an annual basis including accumulated interest beginning in January 2001 and a surcharge of $11.8 million for the billing months of February through July 2001.

In June 2000 SWEPCo filed with the PUCT an application for authority to reconcile fuel costs and to request authorization to carry the unrecovered balance forward into the next reconciliation period. During the reconciliation period of January 1, 1997 through December 31, 1999, SWEPCo incurred $347 million of Texas jurisdiction eligible fuel and fuel-related expenses.

On December 27, 2000, SWEPCo reached a settlement. The settlement resulted in a reduction of $2.25 million of eligible Texas jurisdictional fuel expense, which was prorated equally over thirty-six months of the reconciliation period. The settlement also provides that depreciation and lease expense associated with new aluminum railcars will qualify for treatment as eligible fuel expense from January 1, 2000 forward. Parties to the settlement will support SWEPCo in seeking to amend its 1999 excess earnings report to include 1999 railcar depreciation expense in the depreciation component of the calculation. In February 2001, the PUCT approved the settlement, which did not have a material effect on SWEPCo's results of operations.

WTU Fuel Filings — In August 2000 WTU filed with the PUCT an application for authority to implement an increase in fuel factors effective with the October 2000 billing month. WTU also proposed to implement an interim fuel surcharge to collect its under-recovered fuel costs from August 1, 1999 through June 30, 2000 including accumulated interest, over a six-month period beginning in November 2000.

In December 2000, the PUCT approved WTU's application. The order allows an increase in fuel factors of $42.6 million on an annual basis including accumulated interest and provides for a surcharge of $19.6 million for previously under-recovered fuel costs.

In January 2001 WTU filed with the PUCT an application for authority to implement an increase in fuel factor revenues of $46.5 million effective with the March 2001 billing. Approval by the PUCT is pending.

In December 2000 WTU filed with the PUCT an application for authority to reconcile fuel costs. During the reconciliation period of July 1, 1997 through June 30, 2000, WTU incurred $348 million of Texas jurisdiction eligible fuel and fuel-related expenses. Approval by the PUCT is pending.

OPCo's Recovery of Fuel Costs — Pursuant to PUCO - approved stipulation agreements the cost of coal burned at the Gavin Plant was subject to a 15-year predetermined price of $1.575 per million Btu's with quarterly escalation adjustments through November 2009. To the extent the actual cost of coal burned at the Gavin Plant was below the predetermined prices, the stipulation agreement provided OPCo with the opportunity to recover over its term the Ohio jurisdictional share of OPCo's investment in and the liabilities and future shutdown costs of its affiliated mines as well as any fuel costs incurred above the predetermined rate and deferred for future recovery under the agreements. As a result of the Ohio Act introducing customer choice and a transition to market based pricing for electricity supply in Ohio, these stipulation agreements were superseded effective January 1, 2001. The Company filed under the provisions of the Ohio Act for recovery of all of its generation related regulatory assets including fuel costs deferred under these pre-determined price stipulation agreements. Under the terms of OPCo's PUCO-approved stipulated transition plan, recovery of generation-related regulatory assets at December 31, 2000, which were $518 million, over seven years was approved.

The Muskingum coal strip mine and Windsor deep coal mine which supplied all of their output to OPCo have been closed. Efforts are underway to reclaim the properties, sell or scrap all mining equipment, terminate both capital and operating leases and perform other activities necessary to reclaim the mines. Mine reclamation activities should be completed within two to three years; postremediation monitoring is anticipated to continue for five years after completion of reclamation.

The Company currently plans to close the Meigs deep coal mine by the end of 2001 unless ongoing efforts to sell it are successful. Currently efforts are being made to sell the active Meigs and shutdown Windsor and Muskingum mines.

FERC Jurisdiction

The FERC issued orders 888 and 889 in April 1996 which required 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 and to pay their own transmission service tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a pro-forma tariff, which reflects the Commission's views on the minimum non-price terms and conditions for non-discriminatory transmission service. The FERC orders also allow a utility to seek recovery of certain prudently incurred stranded costs that result from unbundling transmission service.

On July 9, 1996, the AEP System companies filed an Open Access Transmission Tariff conforming with the FERC's pro-forma transmission tariff, subject to the resolution of certain pricing issues. The 1996 tariff incorporated transmission rates which were the result of a settlement of a pending rate case, but which were being collected subject to refund from certain customers who opposed the settlement and continued to litigate the reasonableness of AEP's transmission rates. On July 30, 1999, the FERC issued an order in the litigated rate case that would reduce AEP's rates for the affected customers below the settlement rate. AEP and certain of the affected customers sought rehearing of the Commission's Order. On December 10, 1999, AEP filed a settlement agreement with the FERC resolving the issues on rehearing of the July 30, 1999 order.

On March 16, 2000, the FERC approved the settlement agreement. Under terms of the settlement, AEP is required to make refunds retroactive to September 7, 1993 to certain customers affected by the July 30, 1999 FERC order. The refunds were made in two payments. Pursuant to FERC orders the first payment was made in February 2000 and the second payment was made on August 1, 2000. The Company recorded provisions in 1999 and 2000 for the earnings impact of the required refunds including interest.

The settlement agreement also reduced the rates for transmission service. A new lower rate of $1.55 kw/month was made effective January 1, 2000, for all transmission service customers. Also as agreed, a new rate of $1.42 kw/month took effect on June 16, 2000 upon consummation of the AEP/CSW merger. Prior to January 1, 2000, the rate was $2.04 kw/month. Unless the market volume of physical power transactions grows to increase the utilization of the AEP System's transmission lines, the new open access transmission rate will adversely impact future results of operations and cash flows. Since the rate has been reduced the volume of transmission usage has increased on the AEP System mainly due to increased competition in the wholesale electricity market.

West Virginia

On May 12, 1999, APCo, a subsidiary doing business in WV, filed with the WVPSC for a base rate increase of $50 million annually and a reduction in ENEC rates of $38 million annually. On February 7, 2000, APCo and other parties to the proceeding filed a Joint Stipulation with the WVPSC for approval.

The Joint Stipulation's main provisions include no change in either base or ENEC rates effective January 1, 2000 from those base and ENEC rates in effect from November 1, 1996 until December 31, 1999 (these rates provide for recovery of regulatory assets including any generation-related regulatory assets through frozen transition rates and a wires charge of 0.5 mills per kwh); the continued suspension of annual ENEC recovery proceedings and cessation of existing deferral accounting for all over or under recovery of fuel and purchased power costs net of system sales effective January 1, 2000; and the retention, as a regulatory liability, on the books of a net cumulative deferred ENEC overrecovery balance of $66 million as established by a WVPSC order on December 27, 1996. The Joint Stipulation also provides that when deregulation of generation occurs in WV, APCo will use this retained regulatory liability to reduce generation-related regulatory assets and, to the extent possible, any additional costs or obligations that restructuring and deregulation of APCo's generation business may impose. The elimination of ENEC recovery proceedings in WV will subject AEP and APCo to the risk of fuel market price increases and reductions in wholesale sales levels which could adversely affect results of operations and cash flows.

Also, under the Joint Stipulation, APCo's share of any net savings from the merger between AEP and CSW prior to December 31, 2004 shall be retained by APCo. As a result, all costs incurred in the merger that were allocated to APCo shall be fully charged to expense to partially offset merger savings through December 31, 2004 and shall not be included in any WV rate proceeding after that date. After December 31, 2004, current distribution savings related to the merger will be reflected in rates in any future rate proceeding before the WVPSC to establish distribution rates or to adjust rate caps during the transition to market based generation rates. When deregulation of generation occurs in WV, the net retained generation-related merger savings shall be used to recover any generation-related regulatory assets that are not recovered under the other provisions of the Joint Stipulation and the mechanisms provided for in the deregulation legislation and, to the extent possible, to recover any additional costs or obligations that deregulation may impose on APCo. Regardless of whether the net cumulative deferred ENEC overrecovery balance and the net merger savings are sufficient to offset all of APCo's generation-related regulatory assets, under the terms of the Joint Stipulation there will be no further explicit adjustment to APCo's rates to provide for recovery of generation-related regulatory assets beyond the above discussed specific adjustment provisions in the Joint Stipulation and the 0.5 mills per KWH wires charge in the WV Restructuring Plan (see Note 7 "Industry Restructuring" for discussion of WV Restructuring Plan). On June 2, 2000, the WVPSC issued an order approving the Joint Stipulation. Management expects that the stipulation agreement plus the provisions of pending restructuring legislation will, if the legislation becomes effective, provide for the recovery of existing regulatory assets, other stranded costs and the cost of such deregulation in WV.

6. Effects of Regulation:

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) recorded in accordance with regulatory actions in order to match expenses and revenues from cost-based rates in the same accounting period. Regulatory assets are expected to be recovered in future periods through the rate-making process and regulatory liabilities are expected to reduce future cost recoveries. Among other things, application of SFAS 71 requires that the AEP System's regulated rates be cost-based and the recovery of regulatory assets probable. Management has reviewed all the evidence currently available and concluded that the requirements to apply SFAS 71 continue to be met for all of the Company's electric operations in Indiana, Kentucky, Louisiana, Michigan, Oklahoma and Tennessee.

When the generation portion of the Company's business in Arkansas, Ohio, Texas, Virginia and WV no longer met the requirements to apply SFAS 71, net regulatory assets were written off for that portion of the business unless they were determined to be recoverable as a stranded cost through regulated distribution rates or wire charges in accordance with SFAS 101 Regulated Enterprises — Accounting for the Discontinuation of FASB Statement No. 71 and EITF 97-4 Deregulation of the Pricing of Electricity — Issues Related to the Application of FASB No. 71, Accounting for the Effects of Certain Types of Regulation, and No. 101, Regulated Enterprises — Accounting for the Discontinuation of the Application of FASB Statement No. 71. In the Ohio, Virginia and WV jurisdictions the generation-related regulated assets that are recoverable through transition rates have been transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. In the Texas jurisdiction generation-related regulatory assets that have been tentatively approved for recovery through securitization have been classified as "regulatory assets designated for securitization." (See Note 7 "Industry Restructuring" for further details.)

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

	December 31,	
	2000	1999
	(millions)	
Regulatory Assets:		
Amounts Due From Customers For Future Income Taxes	$914	$1,450
Transition — Regulatory Assets	963	—
Regulatory Assets Designated for Securitization	953	953
Deferred Fuel Costs	407	477
Unamortized Loss on reacquired debt	113	154
Cook Plant Restart Costs	120	160

DOE Decontamination and Decommissioning Assessment	35	39
Other	193	231
Total Regulatory Assets	$3,698	$3,464

	December 31,	
	2000	1999
	(millions)	
Regulatory Liabilities:		
Deferred Investment Tax Credits	$528	$580
Other	208	315
Total Regulatory Liabilities	$736	$895

7. Industry Restructuring:

Restructuring legislation has been enacted in seven of the eleven state retail jurisdictions in which AEP's domestic electric utility companies operate. The legislation provides for a transition from cost-based regulation of bundled electric service to unbundled cost-based rate regulation of transmission and distribution service and customer choice market pricing for the supply of electricity. The enactment of restructuring legislation and the ability to determine transition rates, wires charges and any resultant extraordinary gain or loss under restructuring legislation enabled AEP and certain subsidiaries to discontinue regulatory accounting for the generation portion of the business. Prior to restructuring, the electric utility companies accounted for their operations according to the cost-based regulatory accounting principles of SFAS 71. Under the provisions of SFAS 71, regulatory assets and regulatory liabilities are recorded to reflect the economic effects of regulation to account for the difference between regulatory accounting and GAAP and to match expenses with regulated revenues. The discontinuance of the application of SFAS 71 is in accordance with the provisions of SFAS 101. Pursuant to those provisions and further guidance provided in EITF Issue 97-4, a company is required to write-off regulatory assets and liabilities related to the deregulated operations, unless recovery of such amounts is provided through cost-based regulated rates to be collected in the portion of operations which continues to be rate regulated. Additionally, a company experiencing a discontinuance of cost-based rate regulation is required to determine if any plant assets are impaired under SFAS 121. A SFAS 121 accounting impairment analysis involves estimating cumulative future non-discounted net cash flows arising from the use of assets. If the cumulative undiscounted net cash flows exceed the net book value of the assets, then there is no impairment of the assets for accounting purposes. If there is any accounting impairment, it would be recorded on a discounted basis.

As legislative and regulatory proceedings evolve, the AEP electric operating companies doing business in the seven states that have passed restructuring legislation are applying the standards discussed above to discontinue SFAS 71 regulatory accounting. The following is a summary of the restructuring legislation, the status of the transition plans and the status of the AEP System's electric utility operating companies' accounting to comply with the changes in each of the AEP System's seven state regulatory jurisdictions affected by restructuring legislation.

Ohio Restructuring

Effective January 1, 2001, customer choice of electricity supplier began under the Ohio Act. In February 2001, one supplier announced its plan to offer service to CSPCo's residential customers. Currently for residential customers of OPCo, no alternative suppliers have registered with the PUCO as required by the Ohio Act. Two alternative suppliers have been approved to compete for CSPCo's and OPCo's commercial and industrial customers. Presently, customers continue to be served by CSPCo and OPCo with a legislatively required residential rate reduction of 5% for the generation portion of rates and a freezing of generation rates including fuel rates starting on January 1, 2001.

The Ohio Act provides for a five-year transition period to move from cost based rates to market pricing for generation services. It granted the PUCO broad oversight responsibility for promulgation of rules for competitive retail electric generation service, approval of a transition plan for each electric utility company and addressing certain major transition issues including unbundling of rates and the recovery of stranded costs including regulatory assets and transition costs.

The Ohio Act also provides for a reduction in property tax assessments, the imposition of replacement franchise and income taxes, and the replacement of a gross receipts tax with a KWH based excise tax. The property tax assessment percentage on generation property was lowered from 100% to 25% of value effective January 1, 2001 and Ohio electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which Ohio electric utilities will pay the excise tax based on gross receipts is the tax year ending April 30, 2002. As of May 1, 2001 electric distribution companies will be subject to an excise tax based on KWH sold to Ohio customers. The gross receipts tax is paid at the beginning of the tax year (May 1), deferred by CSPCo and OPCo as a prepaid expense and amortized to expense during the tax year pursuant to the tax law whereby the payment of the tax results in the privilege to conduct business in the year following the payment of the tax. As a result a duplicate tax will be expensed from May 1, 2001 through April 30, 2002 adding approximately $90 million to tax expense during that period. Unless the companies can recover the duplicate amount from ratepayers it will negatively impact results of operations.

On September 28, 2000, the PUCO approved, with minor modifications, a stipulation agreement between CSPCo, OPCo, the PUCO staff, the Ohio Consumers' Counsel and other concerned parties regarding transition plans filed by CSPCo and OPCo. The key provisions of this stipulation agreement are:

- Recovery of generation-related regulatory assets at December 31, 2000 over seven years for OPCo ($518 million) and over eight years for CSPCo ($248 million) through frozen transition rates for the first five years of the recovery period and a wires charge for the remaining years.
- A shopping incentive (a price credit) of 2.5 mills per KWH for the first 25% of CSPCo residential customers that switch suppliers. There is no shopping incentive for OPCo customers.
- The absorption of $40 million by CSPCo and OPCo ($20 million per company) of consumer education, implementation and transition plan filing costs with deferral of the remaining costs, plus a carrying charge, as a regulatory asset for recovery in future distribution rates.
- CSPCo and OPCo will make available a fund of up to $10 million to reimburse customers who choose to purchase their power from another company for certain transmission charges imposed by PJM and/or a Midwest ISO on generation originating in the Midwest ISO or PJM areas.
- The statutory 5% reduction in the generation component of residential tariffs will remain in effect for the entire five year transition period.
- The companies' request for a $90 million gross receipts tax rider to recover the duplicate gross receipts KWH based excise tax would be considered separately by the PUCO.

The approved stipulation agreement also accepted the following provisions contained in CSPCo's and OPCo's filed transition plans:

- a corporate separation plan to segregate generation, transmission and distribution assets into separate legal entities, and
- a plan for independent operation of transmission facilities.

The gross receipts tax issue was considered by the PUCO in hearings held in June 2000. In the September 28, 2000 order approving the stipulation agreement, the PUCO determined that there was no duplicate tax overlap period and denied the request for a $90 million gross receipts tax rider. CSPCo's and OPCo's request for rehearing of the gross receipts tax issue was denied. An appeal of this issue to the Ohio Supreme Court has been filed. Unless this issue is resolved in the companies' favor, it will have an adverse effect on future results of operations and financial position.

One of the intervenors at the hearings for approval of the settlement agreement (whose request for rehearing was denied by the PUCO) has filed with the Ohio Supreme Court for review of the settlement agreement including recovery of regulatory assets. Management is unable to predict the outcome of litigation but the resolution of this matter could negatively impact results of operation.

Beginning January 1, 2001, CSPCo's and OPCo's fuel costs will not be subject to PUCO fuel recovery proceedings. Deferred fuel costs at December 31, 2000 which represent under or over recoveries were one of the items included in the PUCO's final determination of net regulatory assets to be collected (recovered) during the transition period. The elimination of fuel clause recoveries in 2001 in Ohio will subject AEP, CSPCo and OPCo to the risk of fuel market price increases and could adversely affect their future results of operations and cash flows.

CSPCo and OPCo Discontinue Application of SFAS 71 Regulatory Accounting for the Ohio Jurisdiction

In September 2000 CSPCo and OPCo discontinued the application of SFAS 71 for their Ohio retail jurisdictional generation business since generation is no longer cost-based regulated in the Ohio jurisdiction and management was able to determine their transition rates and wires charges. The discontinuance in the Ohio jurisdiction was possible as a result of the PUCO's September 28, 2000 approval of the stipulation agreement which established rates, wires charges and net regulatory asset recovery procedures during the transition to market rates.

CSPCo's and OPCo's discontinuance of SFAS 71 for generation resulted in after tax extraordinary losses in the third quarter of 2000 of $25 million and $19 million, respectively, due to certain unrecoverable generation-related regulatory assets and transition expenses. Management believes that substantially all of the remaining net regulatory assets related to the Ohio generation business will be recovered under the PUCO's September 28, 2000 order. Therefore, under the provisions of EITF 97-4, CSPCo's and OPCo's generation-related recover-able net regulatory assets were transferred to the transmission and distribution portion of the business and will be amortized as they are recovered through transition rates to customers. CSPCo and OPCo performed an accounting impairment analysis on their generating assets under SFAS 121 as required when discontinuing the application of SFAS 71 and concluded there was no impairment of generation assets.

Virginia

In Virginia, a restructuring law provides for a transition to choice of electricity supplier for retail customers beginning on January 1, 2002. In February 2001 restructuring revision legislation was approved by the Virginia Legislature which could modify the terms of restructuring. Presently, the transition period is to be completed, subject to a finding by the Virginia SCC that an effective competitive market exists by January 1, 2004 but no later than January 1, 2005.

The restructuring law also provides an opportunity for recovery of just and reasonable net stranded generation costs. The mechanisms in the Virginia law for net stranded cost recovery are: a capping of rates until as late as July 1, 2007, and the application of a wires charge upon customers who depart the incumbent utility in favor of an alternative supplier prior to the termination of the rate cap. The restructuring law provides for the establishment of capped rates prior to January 1, 2001 based either on a request by APCo for a change in rates prior to January 1, 2001 or on the rates in effect at July 1, 1999 if no rate change request is made and the establishment of a wires charge by the fourth quarter of 2001. APCo did not request new rates; therefore, its current rates are the capped rates. In the third quarter of 2000, the Virginia SCC directed APCo to file a cost of service study using 1999 as a test year to review the reasonableness of APCo's capped rates. The cost of service study was filed on January 3, 2001. In the opinion of AEP's Virginia counsel, Virginia's restructuring law does not permit the Virginia SCC to change rates for the transition period except for changes in the fuel factor, changes in state gross receipts taxes, or to address the utility's financial distress. However, if the Virginia SCC were to reduce APCo's capped rates or deny recovery of regulatory assets, it would adversely affect results of operations if such action is ultimately determined to be legal.

The Virginia restructuring law also requires filings to be made that outline the functional separation of generation from transmission and distribution and a rate unbundling plan. On January 3, 2001, APCo filed its corporate separation plan and rate unbundling plan with the Virginia SCC which is based on the most recent rate case test year (1996). See the heading "Structural Separation" below in this footnote for a discussion of AEP's corporate separation plan filed with the SEC.

West Virginia

On January 28, 2000, the WVPSC issued an order approving an electricity restructuring plan for WV. On March 11, 2000, the WV Legislature approved the restructuring plan by joint resolution. The joint resolution provides that the WVPSC cannot implement the plan until the legislature makes necessary tax law changes to preserve the revenues of the state and local governments. The Joint Committee on Government and Finance of the WV Legislature hired a consultant to study and issue a report on the tax changes required to implement electric restructuring. Moreover, the committee also hired a consultant to study and issue a report on the electric restructuring plan in light of events occurring in California. The WV Legislature is not expected to consider these reports until the 2002 Legislative Session since the 2001 Legislative Session ends in April 2001. Since the WV Legislature has not yet passed the required tax law changes, the restructuring plan has not become effective. AEP subsidiaries, APCo and WPCo, provide electric service in WV.

The provisions of the restructuring plan provide for customer choice to begin after all necessary rules are in place (the "starting date"); deregulation of generation assets on the starting date; functional separation of the generation, transmission and distribution businesses on the starting date and their legal corporate separation no later than January 1, 2005; a transition period of up to 13 years, during which the incumbent utility must provide default service for customers who do not change suppliers unless an alternative default supplier is selected through a WVPSC-sponsored bidding process; capped and fixed rates for the 13 year transition period as discussed below; deregulation of metering and billing; a 0.5 mills per KWH wires charge applicable to all retail customers for a 10-year period commencing with the starting date intended to provide for recovery of any stranded cost including net regulatory assets; establishment of a rate stabilization deferred liability balance of $81 million ($76 million by APCo and $5 million by WPCo) by the end of year ten of the transition period to be used as determined by the WVPSC to offset market prices paid in the eleventh, twelfth, and thirteenth year of the transition period by residential and small commercial customers that do not choose an alternative supplier.

Default rates for residential and small commercial customers are capped for four years after the starting date and then increase as specified in the plan for the next six years. In years eleven, twelve and thirteen of the transition period, the power supply rate shall equal the market price of comparable power. Default rates for industrial and large commercial customers are discounted by 1% for four and a half years, beginning July 1, 2000, and then increased at pre-defined levels for the next three years. After seven years the power supply rate for industrial and large commercial customers will be market based. APCo's Joint Stipulation agreement, discussed in Note 5 "Rate Matters", which was approved by the WVPSC on June 2, 2000 in connection with a base rate filing, also provides additional mechanisms to recover regulatory assets.

APCo Discontinues Application of SFAS 71 Regulatory Accounting

In June 2000 APCo discontinued the application of SFAS 71 for its Virginia and WV retail jurisdictional portions of its generation business since generation is no longer considered to be cost-based regulated in those jurisdictions and management was able to determine APCo's transition rates and wires charges. The discontinuance in the WV jurisdiction was made possible by the June 2, 2000 approval of the Joint Stipulation which established rates, wires charges and regulatory asset recovery procedures for the transition period to market rates which was determined to be probable. APCo was also able to discontinue application of SFAS 71 for the generation portion of its Virginia retail jurisdiction after management decided that APCo would not request capped rates different from its current rates. The existence of effective restructuring legislation in Virginia and the probability that the WV legislation would become effective with the expected probable passage of required enabling tax legislation in 2001 supported management's decision in 2000 to discontinue SFAS 71 regulatory accounting for APCo's electricity generation and supply business.

APCo's discontinuance of SFAS 71 for generation resulted in an after tax extraordinary gain, in the second quarter of 2000, of $9 million. Management believes that it is probable that substantially all net regulatory assets related to the Virginia and WV generation business will be recovered. Therefore, under the provisions of EITF 97-4, APCo's generation-related net regulatory assets were transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, APCo performed an accounting impairment analysis on its generating assets under SFAS 121 and concluded that there was no accounting impairment of generation assets.

The studies requested by the WV Legislature, discussed above, could result in the WV Legislature deciding not to enact the required tax changes, thereby, effectively continuing cost based rate regulation in West Virginia or it could modify the restructuring plan. Modifications in the restructuring plan could adversely affect future results of operations if they were to occur. Management is carefully monitoring the situation in West Virginia and continues to work with all concerned parties to get approval to successfully transition our generation business in West Virginia. Failure to pass the required enabling tax changes could ultimately require APCo to re-instate regulatory accounting principles under SFAS 71 for its generation operations in West Virginia.

Arkansas Restructuring

In 1999 legislation was enacted in Arkansas that will ultimately restructure the electric utility industry. Its major provisions are:

- retail competition begins January 1, 2002 but can be delayed until as late as June 30, 2003 by the Arkansas Commission;

- transmission facilities must be operated by an ISO if owned by a company which also owns generation assets;
- rates will be frozen for one to three years;
- market power issues will be addressed by the Arkansas Commission; and
- an annual progress report to the Arkansas General Assembly on the development of competition in electric markets and its impact on retail customers is required.

In November 2000 the Arkansas Commission filed its annual progress report with the Arkansas General Assembly recommending a delay in the start date of retail competition to a date between October 1, 2003 and October 1, 2005. The report also asks the Arkansas General Assembly to delegate authority to the Arkansas Commission to determine the appropriate retail competition start date within the approved time frame. In February 2001 the Arkansas General Assembly passed legislation that was signed into law by the Governor that changes the date of electric retail competition to October 1, 2003, and provided the Arkansas Commission with the authority to delay that date for up to two years.

Texas Restructuring

In June 1999 Texas restructuring legislation was signed into law which, among other things:

- gives Texas customers of investor-owned utilities the opportunity to choose their electricity provider beginning January 1, 2002;
- provides for the recovery of regulatory assets and of other stranded costs through securitization and non-bypassable wires charges;
- requires reductions in NOx and sulfur dioxide emissions;
- provides for a rate freeze until January 1, 2002 followed by a 6% rate reduction for residential and small commercial customers and a number of customer protections;
- provides for an earnings test for each of the three years of the rate freeze period (1999 through 2001) which will reduce stranded cost recoveries or if there is no stranded cost provides for a refund or their use to fund certain capital expenditures in the amount of the excess earnings;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution utility;
- provides for certain limits for ownership and control of generating capacity by companies;
- provides for elimination of the fuel clause reconciliation process beginning January 1, 2002; and
- provides for a 2004 true-up proceeding to determine recovery of stranded costs including final fuel recovery balances, net regulatory assets, certain environmental costs, accumulated excess earnings and other issues.

Under the Texas Legislation, delivery of electricity will continue to be the responsibility of the local electric transmission and distribution utility company at regulated prices. Each electric utility was required to submit a plan to structurally unbundle its business activities into a retail electric provider, a power generation company, and a transmission and distribution utility. In May 2000 CPL, SWEPCo and WTU filed a revised business separation plan that the PUCT approved on July 7, 2000 in an interim order. The revised business separation plans provided for CPL and WTU, which operate in Texas only, to establish separate companies and divide their integrated utility operations and assets into a power generation company, a transmission and distribution utility and a retail electric provider. SWEPCo will separate its Texas jurisdictional transmission and distribution assets and operations into a new Texas regulated transmission and distribution subsidiary. In addition, a retail electric provider will be formed by SWEPCo to provide retail electric service to SWEPCo's Texas jurisdictional customers.

Under the Texas Legislation, electric utilities are allowed, with the approval of the PUCT, to recover stranded generation costs including generation-related regulatory assets that may not be recoverable in a future competitive market. The approved stranded costs can be refinanced through securitization, which is a financing structure designed to provide lower financing costs than are available through conventional financings. Lower financing costs are achieved through the issuance of securitization bonds at a lower interest rate to finance 100% of the costs pursuant to a state pledge to ensure recovery of the bond principal and financing costs through a non-bypassable rate surcharge by the regulated transmission and distribution utility over the life of the securitization bonds.

In 1999 CPL filed an application with the PUCT to securitize approximately $1.27 billion of its retail generation-related regulatory assets and approximately $47 million in other qualified restructuring costs. On March 27, 2000, the PUCT issued an order permitting CPL to securitize approximately $764 million of net regulatory assets. The PUCT's order authorized issuance of up to $797 million of securitization bonds including the $764 million for recovery of net generation-related regulatory assets and $33 million for other qualified refinancing costs. The $764 million for recovery of net generation-related regulatory assets reflects the recovery of $949 million of generation-related regulatory assets offset by $185 million of customer benefits associated with accumulated deferred income taxes. CPL had previously proposed in its filing to flow these benefits back to customers over the 14-year term of the securitization bonds. On April 11, 2000, four parties appealed the PUCT's securitization order to the Travis County District Court. In July 2000 the Travis County District Court upheld the PUCT's securitization order. The securitization order is being appealed to the Supreme Court of Texas. One of these appeals challenges CPL's ability to recover securitization charges under the Texas Constitution. CPL will not be able to issue the securitization bonds until these appeals are resolved.

The remaining regulatory assets of $206 million originally included by CPL in its 1999 securitization request were included in a March 2000 filing with the PUCT, requesting recovery of an additional $1.1 billion of stranded costs. The March 2000 filing of $1.1 billion included recovery of approximately $800 million of STP costs included in property, plant and equipment-electric on the Consolidated Balance Sheets. These STP costs had previously been identified as excess cost over market (ECOM) by the PUCT for regulatory purposes and were earning a lower return and were being amortized on an accelerated basis for rate-making purposes in Texas. The March 2000 filing will determine the initial amount of stranded costs in addition to the securitized regulatory assets to be recovered beginning January 1, 2002.

CPL submitted a revised estimate of stranded costs on October 2, 2000 using assumptions developed in generic proceedings by the PUCT and an administrative model developed by the PUCT staff that reduced the amount of the initial stranded cost estimate to $361 million from the $1.1 billion requested by CPL. CPL subsequently agreed to accept adjustments proposed by intervenors that reduced ECOM to approximately $230 million. Hearings on CPL's requested ECOM were held in October 2000. In February 2001 the PUCT issued an interim decision determining an initial amount of CPL ECOM or stranded costs of negative $580 million. The decision indicated that CPL's costs were below market after securitization of regulatory assets. Management does not agree with the critical inputs to this model. Management believes CPL has a positive stranded cost exclusive of securitized regulatory assets. The final amount of CPL's stranded costs including regulatory assets and ECOM will be established by the PUCT in the legislatively required 2004 true-up proceeding. If CPL's total stranded costs determined in the 2004 true-up are less than the amount of securitized regulatory assets, the PUCT can implement an offsetting credit to transmission and distribution rates.

The PUCT ruled that prior to the 2004 true-up proceeding, no adjustments would be made to the amount of regulatory costs authorized by the PUCT to be securitized. However, the PUCT also ruled that excess earnings for the period 1999-2001 should be refunded through transmission and distribution rates to the extent of any over-mitigation of stranded costs represented by negative ECOM. In the event that CPL will be required to refund excess earnings in the future instead of applying them to reduce ECOM or regulatory assets, it will adversely affect future cash flow but not results of operations since excess earnings for 1999 and 2000 were accrued and expensed in 1999 and 2000. The Texas Legislation allows for several alternative methods to be used to value stranded costs in the final 2004 true-up proceeding including the sale or exchange of generation assets, the issuance of power generation company stock to the public or the use of PUCT staff's ECOM model. To the extent that the final 2004 true-up proceeding determines that CPL should recover additional stranded costs, the total amount recoverable can be securitized.

The Texas Legislation provides that each year during the 1999 through 2001 rate freeze period, electric utilities are subject to an earnings test. For electric utilities with stranded costs, such as CPL, any earnings in excess of the most recently approved cost of capital in its last rate case must be applied to reduce stranded costs. Utilities without stranded costs, such as SWEPCo and WTU, must either flow such excess earnings amounts back to customers or make capital expenditures to improve transmission or distribution facilities or to improve air quality. The Texas Legislation requires PUCT approval of the annual earnings test calculation.

The 1999 earnings test reports filed by CPL, SWEPCo and WTU showed excess earnings of $21 million, $1 million and zero, respectively. The PUCT staff issued its report on the excess earnings calculations filed by CPL, SWEPCo and WTU and calculated the excess earnings amounts to be $41 million, $3 million and $11 million for CPL, SWEPCo and WTU, respectively. The Office of Public Utility Counsel also filed exceptions to the companies' earnings reports. Several issues were resolved via settlement and the remaining open issues were submitted to the PUCT. A final order was issued by the PUCT in February 2001 and adjustments to the accrued 1999 and 2000 excess earnings were recorded in results of operations in the fourth quarter of 2000. After adjustments the accruals for 1999 excess earnings for CPL and WTU were $24 million and $1 million, respectively. CPL and WTU also recorded an estimated provision for excess 2000 earnings of $16 million and $14 million, respectively.

A Texas settlement agreement in connection with the AEP and CSW merger permits CPL to apply for regulatory purposes up to $20 million of STP ECOM plant assets a year in 2000 and 2001 to reduce excess earnings, if any. For book and financial reporting purposes, STP ECOM plant assets will be depreciated in accordance with GAAP, on a systematic and rational basis unless impaired. CPL will establish a regulatory liability or reduce regulatory assets by a charge to earnings to the extent excess earnings exceed $20 million in 2000 and 2001.

Beginning January 1, 2002, fuel costs will not be subject to PUCT fuel reconciliation proceedings. Consequently, CPL, SWEPCo and WTU will file a final fuel reconciliation with the PUCT to reconcile their fuel costs through the period ending December 31, 2001. Fuel costs have been reconciled by CPL, SWEPCo and WTU through June 30, 1998, December 31, 1999 and June 30, 1997, respectively. WTU is currently reconciling its fuel through June 2000. See discussion in Note 5 "Rate Matters". At December 31, 2000, CPL's, SWEPCo's and WTU's Texas jurisdictional unrecovered deferred fuel balances were $127 million, $20 million and $59 million, respectively. Final unrecovered deferred fuel balances at December 31, 2001 will be included in each company's 2004 true-up proceeding. If the final fuel balances or any amount incurred but not yet reconciled were not recovered, they could have a negative impact on results of operations. The elimination of the fuel clause recoveries in 2002 in Texas will subject AEP, CPL, SWEPCo and WTU to greater risks of fuel market price increases and could adversely affect future results of operations beginning in 2002.

The affiliated retail electric provider of CPL, SWEPCo and WTU will be required to offer residential and small commercial customers (with a peak usage of less than 1000 KW) a rate 6% below rates in effect on January 1, 1999 adjusted for any changes in fuel cost recovery factors since January 1, 1999 (price to beat). The price to beat must be offered to residential and small commercial customers until January 1, 2007. Customers with a peak usage of more than 1000 KW are subject to market rates. The Texas restructuring legislation provides for the price to beat to be adjusted up to two times annually to reflect significant changes in fuel and purchased energy costs.

Discontinuance of the Application of SFAS 71 Regulatory Accounting in Arkansas and Texas

The financial statements of CPL, SWEPCo and WTU have historically reflected the economic effects of regulation by applying the requirements of SFAS 71. As a result of the scheduled deregulation of generation in Arkansas and Texas, the application of SFAS 71 for the generation portion of the business in those states was discontinued in the third quarter of 1999. Under the provisions of EITF 97-4, CPL's generation-related net regulatory assets were transferred to the distribution portion of the business and will be amortized as they are recovered through wires charges to customers. Management believes that substantially all of CPL's generation-related regulatory assets will be recovered under the Texas Legislation. CPL's recovery of generation-related regulatory assets and stranded costs are subject to a final determination by the PUCT in 2004. If future events were to make the recovery through securitization of CPL's generation-related regulatory assets no longer probable, CPL would write-off the portion of such regulatory assets deemed unrecoverable as a non-cash extraordinary charge to earnings.

The Texas Legislation provides that all finally determined stranded costs will be recovered. Since SWEPCo and WTU are not expected to have net stranded costs, all Arkansas and Texas jurisdictional generation-related net regulatory assets were written off as non-recoverable in 1999 when they discontinued application of SFAS 71 regulatory accounting. As required by SFAS 101 when SFAS 71 is discontinued, an accounting impairment analysis for generation assets under SFAS 121 was completed for CPL, SWEPCo and WTU. The analysis showed that there was no accounting impairment of generation assets when the application of SFAS 71 was discontinued. CPL, SWEPCo and WTU will test their generation assets for impairment under SFAS 121 if circumstances change. Management believes that on a discounted basis CPL's generation business net cash flows will likely be less than its generating assets' net book value and together with its generation-related regulatory assets should create a recoverable stranded cost for regulatory purposes under the Texas Legislation. Therefore, management continues to carry on the balance sheet at December 31, 2000, $953 million of generation-related regulatory assets already approved for securitization and $195 million of net generation-related regulatory assets pending approval for securitization in Texas. A final determination of whether they will be securitized and recovered will be made as part of the 2004 true-up proceeding.

CPL, SWEPCo, and WTU continue to analyze the impact of electric utility industry restructuring legislation on their Arkansas and Texas electric operations. Although management believes that the Texas Legislation provides for full recovery of stranded costs and that the companies do not have a recordable accounting impairment, a final determination of whether CPL will experience an accounting loss or whether SWEPCo and WTU will experience any additional accounting loss from an inability to recover generation-related regulatory assets and other restructuring related costs in Texas and Arkansas cannot be made until such time as the regulatory process is complete following the 2004 true-up proceeding in Texas and a determination by the Arkansas Commission. In the event CPL, SWEPCo, and WTU are unable after the 2004 true-up proceeding and after the Arkansas Commission proceedings to recover all or a portion of their generation-related regulatory assets, stranded costs and other restructuring related costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Although Arkansas' delay of retail competition may be having a negative effect on the progress of efforts to transition AEP's generation in Arkansas to market based pricing of electricity, it appears that Texas is moving forward as planned. Management is carefully monitoring the situation in Arkansas and is working with all concerned parties to prudently quicken the pace of the transition. However, changes could occur due to concerns stemming from the California energy crisis and other events which could adversely affect future results of operations in Arkansas and possibly Texas.

Michigan Restructuring

On June 5, 2000, the Michigan Legislation became law. Its major provisions, which were effective immediately, applied only to electric utilities with one million or more retail customers. I&M, AEP's electric operating subsidiary doing business in Michigan, has less than one million customers in Michigan. Consequently, I&M was not immediately required to comply with the Michigan Legislation.

The Michigan Legislation gives the MPSC broad power to issue orders to implement retail customer choice of electric supplier no later than January 1, 2002 including recovery of regulatory assets and stranded costs. On October 2, 2000, I&M filed a restructuring implementation plan as required by a MPSC order. The plan identifies I&M's proposal to file with the MPSC on June 5, 2001 its unbundled rates, open access tariffs, terms of service and supporting schedules. Described in the plan are I&M's intentions and preparation for competition related to supplier transactions, customer transactions, rate unbundling, education programs, and regional transmission organization. The plan contains a proposed methodology to determine stranded costs and implementation costs and requests the continuation of a wires charge for recovery of nuclear decommissioning costs. Approval of the restructuring implementation plan is pending before the MPSC.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan will continue to be cost-based regulated until the MPSC approves rates and wires charges in 2001. The establishment of rates and wires charges under a MPSC approved transition plan will enable management to determine the ability to recover stranded costs including regulatory assets and other implementation costs, a requirement of EITF 97-4 to discontinue the application of SFAS 71.

Upon the discontinuance of SFAS 71, I&M will, if necessary, have to write off its Michigan jurisdictional generation-related regulatory assets and record its unrecorded Michigan jurisdictional liability for decommissioning the Cook Plant to the extent that they cannot be recovered under the transition rates and wires charges. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, I&M will have to perform an accounting impairment analysis under SFAS 121 to determine if the Michigan jurisdictional portion of its generating assets are impaired for accounting purposes.

The amount of regulatory assets recorded on the books at December 31, 2000 applicable to I&M's Michigan retail jurisdictional generation business is approximately $45 million before related tax effects. The estimated unrecorded liability for the Michigan jurisdiction to decommission the Cook Plant ranges from $114 million to $215 million in 2000 non-discounted dollars based upon studies completed during 2000. For the Michigan jurisdiction the Company has accumulated approximately $100 million in trust funds to decommission the Cook Plant. Based on the current information available, management does not anticipate that I&M will experience any material tangible asset accounting impairment or regulatory asset write-offs. Ultimately, however, whether I&M will experience material regulatory asset write-offs will depend on whether the MPSC approves their recovery in future restructuring proceedings.

A determination of whether I&M will experience any asset impairment loss regarding its Michigan retail jurisdictional generating assets and any loss from a possible inability to recover Michigan generation-related regulatory assets, decommissioning obligations and transition costs cannot be made until such time as the rates and the wires charges are determined through the regulatory process. In the event I&M is unable to recover all or a portion of its generation-related regulatory assets, unrecorded decommissioning obligation, stranded costs and other implementation costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Oklahoma Restructuring

In 1997, the Oklahoma Legislature passed restructuring legislation providing for retail open access by July 1, 2002. That legislation called for a number of studies to be completed on a variety of restructuring issues, including an independent system operator, technical, financial, transition and consumer issues. During 1998 and 1999 several of the studies were completed.

The information from the studies was expected to be used in the development of additional industry restructuring legislation during the 2000 legislative session. Several additional electric industry restructuring bills were filed in the 2000 Oklahoma legislative session. The proposed bills generally supplemented the industry restructuring legislation previously enacted in Oklahoma which lacked specific procedures for a transition to market based competitive prices. The industry restructuring legislation previously passed did not delegate the establishment of transition procedures to the Oklahoma Corporation Commission. The 2000 Oklahoma legislative session adjourned in May without passing further restructuring legislation.

The 2001 Oklahoma legislative session convened in early February. No further electric restructuring legislation has passed and proposals have been made to delay the implementation of the transition to customer choice and market based pricing under the restructuring legislation. If the necessary legislation is not passed, the Company's generation and retail electric supply business will remain regulated in Oklahoma. If implementation legislation were to modify the original restructuring legislation in Oklahoma it could have a adverse effect on results of operations.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since PSO's rates for generation in Oklahoma will continue to be cost-based regulated until the Oklahoma Legislature approves further restructuring legislation and transition rates and wires charges are established under an approved transition plan. Until management is able to determine the ability to recover stranded costs which includes regulatory assets and other implementation costs, PSO cannot discontinue application of SFAS 71 accounting under GAAP.

When PSO discontinues application of SFAS 71, it will be necessary to write off Oklahoma jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the transition rates and wires charges, when determined, and record any asset accounting impairments in accordance with SFAS 121.

A determination of whether PSO will experience any asset impairment loss regarding its Oklahoma retail jurisdictional generating assets and any loss from a possible inability to recover Oklahoma generation-related regulatory assets and other transition costs cannot be made until such time as the rates and the wires charges are determined through the legislative and/or regulatory process. In the event PSO is unable to recover all or a portion of its generation-related regulatory assets and implementation costs, Oklahoma restructuring could have a material adverse effect on results of operations and cash flows.

Structural Separation

On November 1, 2000, AEP and certain subsidiaries filed with the SEC for approval to form two separate legal holding company subsidiaries of AEP, the parent company. The purpose of these entities is to legally and functionally separate the competitive market business activities and the subsidiaries performing those competitive activities from the business activities which are cost-based regulated and the subsidiaries that perform those regulated activities. Corporate separation plans have also been filed with regulatory commissions in Arkansas, Ohio, Texas and Virginia to comply with requirements specified in their restructuring legislation. The Texas Legislation requires separate legal entities for generation and distribution assets by January 1, 2002. AEP and its subsidiaries will need approval from the SEC under PUHCA, FERC and certain state regulatory commissions to make these organization changes.

8. Commitments and Contingencies:

Construction and Other Commitments — The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2001-2003 for consolidated domestic and foreign operations are estimated to be $7 billion.

Long-term contracts to acquire fuel for electric generation have been entered into for various terms, the longest of which extends to the year 2014. The contracts provide for periodic price adjustments and contain various clauses that would release the Company from its obligation under certain force majeure conditions.

The AEP System has contracted to sell approximately 1,174 MW of capacity domestically on a long-term basis to unaffiliated utilities. Certain of these contracts totaling 250 mw of capacity are unit power agreements requiring the delivery of energy only if the specified generating unit is available. The power sales contracts expire from 2001 to 2010.

Nuclear Plants — I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. CPL 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 CPL 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 in rates 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 $9.5 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $200 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 $88 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $176 million per nuclear incident payable in annual installments of $20 million. CPL could be assessed $44 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.

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. Cook Plant 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.

SNF Disposal — Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees 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 $211 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, 2000, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and approximate the liability. CPL 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. After expiration of the licenses, Cook Plant is expected to be decommissioned through dismantlement. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs for Cook Plant ranges from $783 million to $1,481 million in 2000 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 $28 million in 2000, $28 million in 1999 and $29 million in 1998.

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 decontamination method. CPL estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. CPL is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of $8 million per year.

Decommissioning costs recovered from customers are deposited in external trusts. In 2000 and 1999 I&M deposited in its decommissioning trust an additional $6 million and $4 million, respectively, related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. Decommissioning costs are recorded in other operation expense. During 1999 and 1998 I&M withdrew $8 million and $3 million, respectively, from the trust fund for decommissioning of the original steam generators removed from Cook Plant Unit 2.

On the balance sheets, nuclear decommissioning trust assets are included in other assets and a corresponding nuclear decommissioning liability is included in other noncurrent liabilities. At December 31, 2000 and 1999, the decommissioning liability was $654 million and $587 million, respectively.

Shareholders' Litigation — On June 23, 2000, a complaint was filed in the U.S. District Court for the Eastern District of New York seeking unspecified compensatory damages against AEP and four former or present officers. The individual plaintiff also seeks certification as the representative of a class consisting of all persons and entities who purchased or otherwise acquired AEP common stock between July 25, 1997, and June 25, 1999. The complaint alleges that the defendants knowingly violated federal securities laws by disseminating materially false and misleading statements concerning, among other things, the undisclosed materially impaired condition of the Cook Plant, AEP's inability to properly monitor, manage, repair, supervise and report on operations at the Cook Plant and the materially adverse conditions these problems were having, and would continue to have, on AEP's deteriorating financial condition, and ultimately on AEP's operations, liquidity and stock price. Four other similar class action complaints have been filed and the court has consolidated the five cases. The plaintiffs filed a consolidated complaint pursuant to this court order. This case has been transferred to the U.S. District Court for the Southern District of Ohio. Although management believes these shareholder actions are without merit and intends to oppose them vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

Municipal Franchise Fee Litigation — CPL has been involved in litigation regarding municipal franchise fees in Texas as a result of a class action suit filed by the City of San Juan, Texas in

1996. The City of San Juan claims CPL underpaid municipal franchise fees and seeks damage of up to $300 million plus attorney's fees. CPL filed a counterclaim for overpayment of franchise fees.

During 1997, 1998 and 1999 the litigation moved procedurally through the Texas Court System and was sent to mediation without resolution.

In 1999 a class notice was mailed to each of the cities served by CPL. Over 90 of the 128 cities declined to participate in the lawsuit. However, CPL has pledged that if any final, non-appealable court decision in the litigation awards a judgement against CPL for a franchise underpayment, CPL will extend the principles of that decision, with regard to any franchise underpayment, to the cities that declined to participate in the litigation. In December 1999, the court ruled that the class of plaintiffs would consist of approximately 30 cities. A trial date for June 2001 has been set.

Although management believes that it has substantial defenses to the cities' claims and intends to defend itself against the cities' claims and pursue its counterclaims vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

Texas Base Rate Litigation — In November 1995 CPL filed with the PUCT a request to increase its retail base rates by $71 million. In October 1997 the PUCT issued a final order which lowered CPL's annual retail base rates by $19 million from the rate level which existed prior to May 1996. The PUCT also included a "glide path" rate methodology in the final order pursuant to which annual rates were reduced by $13 million beginning May 1, 1998 with an additional annual reduction of $13 million commencing on May 1, 1999.

CPL appealed the final order to the Travis District Court. The primary issues being appealed include: the classification of $800 million of invested capital in STP as ECOM and assigning it a lower return on equity than other generation property; the use of the "glide path" rate reduction methodology; and an $18 million disallowance of service billings from an affiliate, CSW Services. As part of the appeal, CPL sought a temporary injunction to prohibit the PUCT from implementing the "glide path" rate reduction methodology. The temporary injunction was denied and the "glide path" rate reduction was implemented. In February 1999 the Travis District Court affirmed the PUCT order in regard to the three major items discussed above.

CPL appealed the Travis District Court's findings to the Texas Appeals Court which in July 2000, issued its opinion upholding the Travis District Court except for the disallowance of affiliated service company billings. Under Texas law, specific findings regarding affiliate transactions must be made by PUCT. In regards to the affiliate service billing issue, the findings were not complete in the opinion of the Texas Appeals Court who remanded the issue back to PUCT.

CPL has sought a rehearing of the Texas Appeals Court's opinion. The Texas Appeals Court has requested briefs related to CPL's rehearing request from interested parties. Management is unable to predict the final resolution of its appeal. If the appeal is unsuccessful the PUCT's 1997 order will continue to adversely affect results of operations and cash flows.

As part of the AEP/CSW merger approval process in Texas, a stipulation agreement was approved which resulted in the withdrawal of the appeal related to the "glide path" rate methodology. CPL will continue its appeal of the ECOM classification for STP property and the disallowed affiliated service billings.

Lignite Mining Agreement Litigation — SWEPCo and CLECO are each a 50% owner of Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. In 1982, SWEPCo and CLECO entered into a lignite mining agreement with DHMV, a partnership for the mining and delivery of lignite from a portion of these reserves.

In April 1997, SWEPCo and CLECO sued DHMV and its partners in U.S. District Court for the Western District of Louisiana seeking to enforce various obligations of DHMV under the lignite mining agreement, including provisions relating to the quality of delivered lignite, pricing, and mine reclamation practices. In June 1997, DHMV filed an answer denying the allegations in the suit and filed a counterclaim asserting various contract-related claims against SWEPCo and CLECO. SWEPCo and CLECO have denied the allegations contained in the counterclaims. In January 1999, SWEPCo and CLECO amended the claims against DHMV to include a request that the lignite mining agreement be terminated.

In April 2000, the parties agreed to settle the litigation. As part of the settlement, DHMV's interest in the mining operations and related debt and other obligations will be purchased by SWEPCo and CLECO. The closing date for the settlement has been extended from December 31, 2000 to March 31, 2001. The litigation has been stayed until April 2001 to give the parties time to consummate the settlement agreement.

Management believes that the resolution of this matter will not have a material effect on results of operations, cash flows or financial condition.

Federal EPA Complaint and Notice of Violation — Under the Clean Air Act, 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 AEP System has been involved in litigation regarding generating plant emissions under the Clean Air Act. In 1999 Notices of Violation were issued and complaints were filed by Federal EPA in various U.S. District Courts alleging the AEP System and eleven unaffiliated utilities made modifications to generating units at certain of their coal-fired generating plants over the course of the past 25 years that extended unit operating lives or increased unit generating capacity without a preconstruction permit in violation of the Clean Air Act. The complaint against the AEP System was amended in March 2000 to add allegations for certain generating units previously named in the complaint and to include additional AEP System generating units previously named only in the Notices of Violation in the complaint.

A number of northeastern and eastern states were granted leave to intervene in the Federal EPA's action against the AEP System under the Clean Air Act. A lawsuit against power plants owned by the AEP System alleging similar violations to those in the Federal EPA complaint and Notices of Violation was filed by a number of special interest groups and has been consolidated with the Federal EPA action.

The Clean Air Act 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). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts Federal EPA's contentions, could be substantial.

On May 10, 2000, the AEP System filed motions to dismiss all or portions of the complaints. Briefing on these motions was completed on August 2, 2000. On February 23, 2001, the government filed a motion for partial summary judgement seeking a determination that four projects undertaken on units at Sporn, Cardinal and Clinch River plants do not constitute "routine maintenance, repair and replacement" as used in the Clear Air Act. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense.

In the event the AEP System does 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 where states are deregulating generation, unbundled transition period generation rates, stranded cost wires charges and future market prices for electricity.

In December 2000 Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by AEP's subsidiary, CSPCo, reached a tentative agreement with Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. 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 which are 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 earnings.

NOx Reductions — Federal EPA issued a NOx rule that required substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. A number of utilities, including several AEP System companies, filed petitions seeking a review of the final rule in the D.C. Circuit Court. In March 2000, the D.C. Circuit Court issued a decision generally upholding the NOx rule. The D.C. Circuit Court issued an order in August 2000 which extends the final compliance date to May 31, 2004. In September 2000 following denial by the D.C. Circuit Court of a request for rehearing, the industry petitioners, including the AEP System companies, petitioned the U.S. Supreme Court for review, which was denied.

In December 2000 Federal EPA ruled that eleven states, including certain states in which the AEP System's generating units are located, failed to submit plans to comply with the mandates of the NOx rule. This determination means that those states could face stringent sanctions within the next 24 months including limits on construction of new sources of air emissions, loss of federal highway funding and possible Federal EPA takeover of state air quality management programs.

In January 2000 Federal EPA adopted a revised rule granting petitions filed by certain northeastern states under Section 126 of the Clean Air Act seeking significant reductions in nitrogen oxide emissions from utility and industrial sources. The rule imposes emissions reduction requirements comparable to the NOx rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Certain AEP companies and other utilities filed petitions for review in the D.C. Circuit Court. Briefing has been completed and oral argument was held in December 2000.

In a related matter, on April 19, 2000, the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NOx emissions from utility sources, including CPL and SWEPCo. The rule's compliance date is May 2003 for CPL and May 2005 for SWEPCo.

In June 2000 OPCo announced that it was beginning a $175 million installation of selective catalytic reduction technology (expected to be operational in 2001) to reduce NOx emissions on its two-unit 2,600 MW Gavin Plant. Construction of selective catalytic reduction technology on Amos Plant Unit 3, which is jointly owned by OPCo and APCo, and APCo's Mountaineer Plant is scheduled to begin in 2001. The Amos and Mountaineer projects (expected to be completed in 2002) are estimated to cost a total of $230 million.

Preliminary estimates indicate that compliance with the NOx rule upheld by the D.C. Circuit Court as well as compliance with the Texas Natural Resource Conservation Commission rule and the Section 126 petitions could result in required capital expenditures of approximately $1.6 billion including the amounts discussed in the previous paragraph for the AEP System. Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the preliminary estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers through regulated rates and/or future market prices for electricity where generation is deregulated, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

COLI Litigation — On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against AEP in its suit against the United States over deductibility of interest claimed by AEP in its consolidated federal income tax return related to its COLI program. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 the Company paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced by $319 million in 2000. The Company plans to appeal the decision.

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

9. Acquisitions:

The Company completed two energy related acquisitions in 1998 through a subsidiary, AEPR. Both acquisitions have been accounted for using the purchase method. On December 31, 1998 CitiPower, an Australian distribution utility, that serves approximately 250,000 customers in Melbourne with 3,100 miles of distribution lines in a service area of approximately 100 square miles was acquired. All of the stock of CitiPower was acquired for approximately $1.1 billion. The acquisition of CitiPower had no effect on the results of operations for 1998 and a full year of CitiPower's results of operations are included in the consolidated statements of income for 1999 and 2000. Assets acquired and liabilities assumed have been recorded at their fair values. Based on an independent appraisal, $616 million of the purchase price was allocated to retail and wholesale distribution licenses which are being amortized on a straight-line basis over 20 years and 40 years, respectively. The excess of cost over fair value of the net assets acquired was approximately $34 million and is recorded as goodwill and is being amortized on a straight-line basis over 40 years.

On December 1, 1998 AEPR acquired Louisiana Intrastate Gas (LIG) with midstream gas operations that include a fully integrated natural gas gathering, processing, storage and transportation operation in Louisiana and a gas trading and marketing operation. LIG was acquired for approximately $340 million, including working capital funds with one month of earnings reflected in AEP's consolidated results of operations for the year ended December 31, 1998. A full year of LIG's results of operations is included in the consolidated statements of income for 1999 and 2000. Assets acquired and liabilities assumed have been recorded at their fair values. The excess of cost over fair value of the net assets acquired was approximately $158 million for the midstream gas storage operations and $17 million for the gas trading and marketing operation. The goodwill is being amortized on a straight-line basis over 40 years and 10 years, respectively.

10. International Investments:

CSW International owns a 44% equity interest in Vale, a Brazilian electric operating company which it had purchased for a total of $149 million. The investment is covered by a put option, which, if exercised, requires CSW International's partners in Vale to purchase CSW International's

Vale shares at a minimum price equal to the U.S. dollar equivalent of CSW International's purchase price. As a result, management has concluded that CSW International's investment carrying amount will not be reduced below the put option value unless it is deemed to be a permanent impairment and CSW International's partners in Vale are deemed unable to fulfill their responsibilities under the put option. Vale has experienced losses from operations and CSW International's investment has been affected by the devaluation of the Brazilian Real. CSW International's cumulative equity share of these operating and foreign currency translation losses through December 31, 2000 is approximately $33 million, net of tax, and $49 million, net of tax, respectively. Pursuant to the put option arrangement, these losses have not been applied to reduce the carrying value of the Vale investment. As a result, CSW International will not recognize any future earnings from Vale until the operating losses are recovered.

In December 2000, CSW International sold its investment in a Chilean electric company for $67 million. A net loss on the sale of $13 million ($9 million after tax) is included in worldwide electric and gas expenses and includes $26 million ($17 million net of tax) of losses from foreign exchange rate changes that were previously reflected in other comprehensive income. In the second quarter of 2000 management determined that the then existing decline in market value of the shares was other than temporary. As a result the investment was written down by $33 million ($21 million after tax) in June 2000. The total loss from both the write down of the Chilean investment to market in the second quarter and from the sale in the fourth quarter was $46 million ($30 million net of tax).

In December 2000 the Company entered into negotiations to sell its 50% investment in Yorkshire, a U.K. electricity supply and distribution company. On February 26, 2001 an agreement to sell the Company's 50% interest in Yorkshire was signed. As a result a $43 million impairment writedown ($30 million after tax) was recorded in the fourth quarter of 2000 to reflect the net loss from the expected sale in the first quarter of 2001. The impairment writedown is included in other income (net) on AEP's Consolidated Statements of Income.

11. Staff Reductions:

During 1998 an internal evaluation of the power generation organization was conducted with a goal of developing an optimum organizational structure for a competitive generation market. The study was completed in October 1998 and called for the elimination of approximately 450 positions. In addition, a review of energy delivery staffing levels in 1998 identified 65 positions for elimination.

A provision for severance costs totaling $26 million was recorded in December 1998 for reductions in power generation and energy delivery staffs and was charged to maintenance and other operation expense in the Consolidated Statements of Income. The power generation and energy delivery staff reductions were made in the first quarter of 1999. The amount of severance benefits paid was not significantly different from the amount accrued.

12. Benefit Plans:

In the U.S. the AEP System sponsors two qualified pension plans and two nonqualified pension plans. All employees in the U.S., except participants in the UMWA pension plans are covered by one or both of the pension plans. OPEB plans are sponsored by the AEP System to provide medical and death benefits for retired employees in the U.S.

The foreign pension plans are for employees of SEEBOARD in the U.K. and CitiPower in Australia. The majority of SEEBOARD's employees joined a pension plan that is administered for the U.K.'s electricity industry. The assets of this plan are actuarially valued every three years. SEEBOARD and its participating employees both contribute to the plan. Subsequent to July 1, 1995, new employees were no longer able to participate in that plan and two new pension plans were made available to new employees of SEEBOARD. CitiPower sponsors a defined benefit pension plan that covers all employees.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2000, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		Foreign Pension Plans		U.S. OPEB Plans	
	2000	1999	2000	1999	2000	1999
	(in millions)					
Reconciliation of benefit obligation:						
Obligation at January 1	$2,934	$3,117	$1,176	$1,147	$1,365	$1,297
Service Cost	60	71	13	15	29	33
Interest Cost	227	211	64	59	106	90
Participant Contributions	—	—	5	4	7	9
Plan Amendments	(71)(a)	7(b)	—	7(c)	(67)(d)	—
Foreign Currency Translation Adjustment	—	—	(95)	(26)	—	—
Actuarial (Gain) Loss	218	(300)	80	37	262	—
Benefit Payments	(207)	(172)	(64)	(67)	(85)	(74)
Curtailments	—	—	—	—	51(e)	10(e)
Obligation at December 31	$3,161	$2,934	$1,179	$1,176	$1,668	$1,365
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$3,866	$3,665	$1,405	$1,338	$668	$560
Actual Return on Plan Assets	250	370	55	156	2	71
Company Contributions	2	2	—	7	112	103
Participant Contributions	—	—	5	4	7	9

Foreign Currency Translation Adjustment	—	—	(111)	(33)	—	—
Benefit Payments	(207)	(172)	(64)	(67)	(85)	(74)
Fair value of plan assets at December 31	$3,911	$3,865	$1,290	$1,405	$704	$669
Funded status:						
Funded status at December 31	$750	$931	$111	$229	$(964)	$(696)
Unrecognized Net Transition (Asset) Obligation	(23)	(31)	—	—	298	434
Unrecognized Prior-Service Cost	(12)	71	10	11	—	—
Unrecognized Actuarial (Gain) Loss	(628)	(954)	(67)	(177)	448	135
Prepaid Benefit (Accrued Liability)	$87	$17	$54	$63	$(218)	$(127)

(a) One of the qualified pension plans converted to the cash balance pension formula from a final average pay formula.

(b) Early retirement factors for one of the pension plans was changed to provide more generous benefits to participants retiring between ages 55 and 60.

(c) SEEBOARD made a one-time payment to all retired participants.

(d) Change to a service-related formula for retirement health care costs and a 50% of pay life insurance benefit for retiree life insurance.

(e) Related to the shutdown of affiliated coal mine operations.

The following table provides the amounts recognized in the consolidated balance sheets as of December 31 of both years:

	U.S. Pension Plan		Foreign Pension Plans		U.S. OPEB Plans	
	2000	1999	2000	1999	2000	1999
			(in millions)			
Prepaid Benefit Costs	$159	$145	$54	$63	$—	$—
Accrued Benefit Liability	(72)	(128)	—	—	(218)	(127)
Additional Minimum Liability	(24)	(14)	—	—	N/A	N/A
Intangible Asset	14	8	—	—	N/A	N/A

Accumulated Other Comprehensive Income	10	6	—	—	N/A	N/A
Net Amount Recognized	$87	$17	$54	$63	$(218)	$(127)
Other Comprehensive (Income) Expense Attributable to Change in Additional Pension Liability Recognition	$4	$(2)	—	—	N/A	N/A

N/A = Not Applicable

The Company's nonqualified pension plans had accumulated benefit obligations in excess of plan assets of $41 million and $26 million at December 31, 2000 and $29 million and $23 million at December 31, 1999. There are no plan assets in the nonqualified plans.

The Company's OPEB plans had accumulated benefit obligations in excess of plan assets of $964 million and $696 million at December 31, 2000 and 1999, respectively.

The following table provides the components of net periodic benefit cost for the plans for fiscal years 2000, 1999 and 1998:

	U.S. Pension Plans			Foreign Pension Plans			U.S. OPEB Plans		
	2000	1999	1998	2000	1999	1998	2000	1999	1998
	(in millions)								
Service cost	$60	$71	$67	$13	$15	$14	$29	$33	$26
Interest cost	227	211	202	64	59	68	106	90	76
Expected return on plan assets	(321)	(299)	(269)	(75)	(71)	(77)	(57)	(49)	(40)
Amortization of transition (asset) obligation	(8)	(8)	(8)	—	—	—	41	43	41
Amortization of prior-service cost	13	12	9	1	—	—	—	—	—
Amortization of net actuarial (gain) loss	(39)	(15)	(3)	—	—	—	4	5	(2)
Net periodic benefit cost	(68)	(28)	(2)	3	3	5	123	122	101
Curtailment loss(a)	—	—	—	—	—	—	79	18	24
Net periodic benefit cost after curtailments	$(68)	$(28)	$(2)	$3	$3	$5	$202	$140	$125

(a) Curtailment charges were recognized during 2000, 1999 and 1998 for the shutdown of affiliated coal mine operations.

The assumptions used in the measurement of the Company's benefit obligations are shown in the following tables:

	U.S. Pension Plans			Foreign Pension Plans		
	2000	1999	1998	2000	1999	1998
Weighted-average assumptions as of December 31:						
Discount rate	7.50%	8.00%	6.75%	5-5.5%	5.5-6%	5-5.5%
Expected return on plan assets	9.00%	9.00%	9.00%	6-7.5%	6.5-7.5%	6.25-7%
Rate of compensation increase	3.2%	3.8%	3.8%	3.5-4.0%	4-4.5%	3.5-4%

	U.S. OPEB Plans		
	2000	1999	1998
Weighted-average assumptions as of December 31:			
Discount rate	7.50%	8.00%	6.75%
Expected return on plan assets	8.75%	8.75%	8.75%
Rate of compensation increase	N/A	N/A	N/A

For measurement purposes, a 6.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2001. The rate was assumed to decrease gradually each year to a rate of 5.1% through 2005 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on total service and interest cost components of net periodic postretirement health care benefit cost	$15	$(13)
Effect on the health care component of the accumulated postretirement benefit obligation	197	(162)

AEP System Savings Plans — The AEP System Savings Plans are defined contribution plans offered to non-UMWA U.S. employees. The cost for contributions to these plans totaled $37 million in 2000 and $36 million in 1999 and $35 million in 1998. Beginning in 2001 AEP's contributions to the plans will increase to 4.5% of the initial 6% of employee pay contributed from the current 3% of the initial 6% of employee base pay contributed.

Other UMWA Benefits — The Company provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements.

The benefits are administered by UMWA trustees and contributions are made to their trust funds. Contributions are based on hours worked and are expensed as paid as part of the cost of active mining operations and were not material in 2000, 1999 and 1998.

13. Stock-Based Compensation:

In 2000, AEP adopted a Long-term Incentive Plan under which a maximum of 15,700,000 shares of common stock can be issued to key employees.

Under the plan, the exercise price of each option granted equals the market price of AEP's common stock on the date of grant. These options will vest in equal increments, annually, over a three-year period beginning on January 1, 2002 with a maximum exercise term of ten years.

CSW maintained a stock option plan prior to the merger with AEP. 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. The provisions of the CSW stock option plan will continue in effect until all options expire or there are no longer options outstanding. Under the CSW stock option plan, the option exercise price was equal to the stock's market price on the date of grant. The grant vested over three years, one-third on each of the first three anniversary dates of the grant, and expires 10 years after the original grant date. All CSW stock options were fully vested at December 31, 2000.

The following table summarizes share activity in the above plans, and the weighted-average exercise price:

	2000		1999		1998	
	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	825	$40	866	$40	1,141	$40
Granted	6,046	$36	—	$—	—	$—
Exercised	(26)	$36	(22)	$38	(202)	$40
Forfeited	(235)	$39	(19)	$43	(73)	$40
Outstanding at end of year	6,610	$36	825	$40	866	$40
Options Exercisable at end of year	588	$41	707	$42	606	$43

The weighted-average fair value of options granted in 2000 is $36 per share. No options were granted in 1999 or 1998. Shares outstanding under the stock option plan have exercise prices ranging from $35 to $49 and a weighted-average remaining contractual life of 9.2 years.

If compensation expense for stock options had been determined based on the fair value at the grant date, net income and earnings per share would have been the pro forma amounts shown below:

	2000	1999	1998
Pro forma net income (in millions)	$264	$972	$975
Pro forma earnings per share (basic and diluted)	$0.82	$3.03	$3.06

The pro forma amounts are not representative of the effects on reported net income for future years.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used to estimate the fair value of options granted in 2000: dividend yield of 6.02%; expected stock price volatility of 24.75%; risk-free interest rate of 5.02% and expected life of option of 7 years.

14. Business Segments:

AEP's principal business segment is its cost-based rate regulated Domestic Electric Utility business consisting of eleven regulated utility operating companies providing generation, distribution and transmission electric services in eleven states. Also included in this segment are AEP's electric power wholesale marketing and trading activities conducted within two transmission systems of the AEP System.

The AEP consolidated income statement caption "Revenues-Domestic Electric Utility Operations" includes both the retail and wholesale domestic electricity supply businesses which are cost-based rate regulated on a bundled basis with transmission and distribution services in Kentucky, Indiana, Michigan, Louisiana, Oklahoma and Tennessee and are in the process of transitioning to customer choice market based pricing in Arkansas, Ohio, Texas, WV and Virginia. Since the domestic electric utility companies have not yet functionally or structurally separated their retail and wholesale electricity supply business from their regulated transmission and distribution service business, separate financial data is not available and the Domestic Electric Utilities business will continue to be reported as one business segment which is the only reportable segment for the domestic electric operating subsidiaries.

The AEP consolidated income statement caption "Revenues-Worldwide Electric and Gas Operations" includes three segments: Foreign Energy Delivery, Worldwide Energy Investments and other. The Foreign Energy Delivery segment includes investments in overseas electric distribution and supply companies (SEEBOARD and Yorkshire in the U.K. and CitiPower in Australia).

The Worldwide Energy Investments segment represents domestic and international investments in energy-related gas and electric projects including the development and management of those projects. Such investment activities include electric generation in Florida, Texas, Colorado, Brazil and Mexico, and natural gas pipeline, storage and other natural gas services in the U.S.

The other segment which is included in the AEP consolidated income statement as part of Worldwide Electric and Gas Operations includes non-regulated electric marketing and trading activities outside of AEP's marketing area (beyond two transmission systems from the AEP System) gas marketing and trading activities, telecommunication services, and the marketing of various energy related products and services.

In the fourth quarter of 2000, management announced its intent to functionally and structurally separate its operations into two main business segments, a non-regulated business and a regulated business. Separation of AEP's regulated bundled generation, distribution and transmission businesses into an unbundled non-regulated generation business and regulated unbundled distribution and transmission business will not be completed until the required regulatory approvals are obtained and the electric operating subsidiaries operating in states that are deregulating the generation business are structurally separated and the remaining subsidiaries functionally separated and the necessary changes are made to their accounting software, books, and records. Management expects to begin reporting certain segmented information by the new business segments in the near future.

Year	Domestic* Electric Utilities	Foreign Energy Delivery	Worldwide Energy Investments	Other	Reconciling Adjustments	AEP Consolidated
			(in millions)			
2000						
Revenues from:						
External unaffiliated customers	$10,827	$1,934	$836	$97	—	$13,694
Transactions with other operating segments	—	—	147	391	$(538)	—
Interest expense	734	163	129	91	(60)	1,057
Depreciation, depletion and amortization expense	1,062	149	25	13	(187)	1,062
Income tax expense (benefit)	641	(16)	(19)	(9)	—	597
Segment net income (loss)	211	125	(56)	(13)	—	267
Total assets	35,741	4,446	2,089	12,272	—	54,548
Investments in equity method subsidiaries	—	427	360	77	—	864
Gross property additions	1,386	177	149	61	—	1,773
1999						
Revenues from:						
External unaffiliated customers	$9,838	$2,023	$583	$(37)	—	$12,407
Transactions with other operating segments	—	—	70	246	$(316)	—
Interest expense	688	172	109	55	(47)	977
Depreciation, depletion and amortization expense	1,011	166	26	9	(201)	1,011
Income tax expense (benefit)	490	18	(10)	(16)	—	482
Segment net income (loss)	794	170	34	(26)	—	972
Total assets	27,288	4,739	1,669	2,023	—	35,719
Investments in equity method subsidiaries	—	412	420	57	—	889
Gross property additions	1,215	206	205	54	—	1,680
1998						

Revenues from:						
External unaffiliated customers	$ 9,834	$1,769	$183	$54	—	$11,840
Transactions with other operating segments	—	—	—	49	$(49)	—
Interest expense	682	116	68	51	(38)	879
Depreciation, depletion and amortization expense	989	95	13	7	(115)	989
Income tax expense (benefit)	532	4	(14)	(20)	—	502
Segment net income (loss)	884	155	(26)	(38)	—	975
Total assets	25,546	4,504	1,672	1,543	—	33,265
Investments in equity method subsidiaries	—	352	287	59	—	698
Gross property additions	729	1,259	712	90	—	2,790

* Includes the domestic generation retail and wholesale supply businesses a significant portion of which is undergoing a transition from regulated cost based bundled rates to open access market pricing but which have not yet been unbundled i.e., structurally separated from the distribution and transmission portions of the vertically integrated electric utility business.

Geographic Areas	Revenues			
	United States	United Kingdom	Other Foreign	AEP Consolidated
	(in millions)			
2000	$11,663	$1,632	$399	$13,694
1999	10,353	1,705	349	12,407
1998	10,063	1,769	8	11,840

	Long-Lived Assets			
	United States	United Kingdom	Other Foreign	AEP Consolidated
	(in millions)			
2000	$20,463	$1,220	$710	$22,393
1999	19,958	1,124	783	21,865
1998	19,752	1,102	665	21,519

15. Financial Instruments, Credit and Risk Management:

AEP and its subsidiaries are subject to market risk as a result of changes in commodity prices, foreign currency exchange rates, and interest rates. The Company has wholesale electricity and gas trading and marketing operations that manage the exposure to commodity price movements using physical forward purchase and sale contracts at fixed and variable prices, and financial derivative instruments including exchange traded futures and options, over-the-counter options, swaps and other financial derivative contracts at both fixed and variable prices.

Physical forward electricity contracts within AEP's traditional economic market area are recorded on a net basis as domestic electric utility operations revenues in the month when the physical contract settles. Physical forward electricity contracts outside AEP's traditional marketing area, and all financial electricity trading transactions where the underlying physical commodity is outside AEP's traditional economic market area are recorded on a net basis in worldwide electric and gas operations revenues.

In the first quarter of 1999 the Company adopted the Financial Accounting Standards Board's EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities". The EITF requires that all open energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market in the Company's regulated jurisdictions are deferred as regulatory assets or liabilities in accordance with SFAS 71 for the portion of those open electricity trading transactions within the Company's marketing area that are included in cost of service on a settlement basis for ratemaking purposes. Open electricity trading transactions within the Company's marketing area allocated to non-regulated jurisdictions are marked-to-market and included in revenues from domestic electric utility operations. Open electricity trading contracts outside the Company's marketing area are accounted for on a mark-to-market basis and included in revenues from worldwide electric and gas operations. Open gas trading contracts are accounted for on a mark-to-market basis and included in revenues from worldwide electric and gas operations. Unrealized mark-to-market gains and losses from trading of financial instruments are reported as assets and liabilities, respectively.

The amounts of net revenues recorded in 2000 and 1999 for electric and gas trading activities were:

Revenues — Net Gain (Loss)	2000	1999
	(in millions)	
Domestic Electric Utility Operations	$ 43	$27
Worldwide Electric and Gas Operations	213	14

Investment in foreign energy companies and projects exposes the Company to risk of foreign currency fluctuations. The Company is also exposed to changes in interest rates primarily due to short- and long-term borrowings used to fund its business operations. The Company does not presently utilize derivatives to manage its exposures to foreign currency exchange rate movements.

Market Valuation — The book values of cash and cash equivalents, accounts receivable, short-term debt and accounts payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the Company's best estimate of its fair value.

The book values and fair values of the Company's significant financial instruments at December 31, 2000 and 1999 are summarized in the following table. 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 of the same remaining maturities. The fair value of those financial instruments that are marked-to-market are based on management's best estimates using over-the-counter quotations, exchange prices, volatility factors and a valuation methodology. The estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange.

	Book Value	Fair Value
	(in millions)	
Non-Derivatives		
2000		
Long-term Debt	$10,754	$10,812
Preferred Stock	100	98
Trust Preferred Securities	334	326
1999		
Long-term Debt	$11,524	$11,037
Preferred Stock	119	117
Trust Preferred Securities	335	290

Derivatives

	2000			1999		
	Notional Amount	Fair Value	Average Fair Value	Notional Amount	Fair Value	Average Fair Value
Trading Assets						
	GWH	(in millions)		GWH	(in millions)	
Electric						
Futures and Options-NYMEX (net)	—	$—	$—	224	$2	$1
Physicals	247,330	8,845	2,758	69,509	577	517
Options - OTC	8,981	215	99	6,203	39	62
Swaps	11,575	164	60	177	1	1
	MMMBTU	(in millions)		MMMBTU	(in millions)	
Gas						
Futures and Options-NYMEX (net)	—	$—	$—	—	$—	$—
Physicals	597,251	455	97	345,830	37	39
Options - OTC	698,392	1,266	355	192,593	54	40
Swaps	4,677,142	7,328	1,730	2,682,033	410	312
Trading Liabilities						
	GWH	(in millions)		GWH	(in millions)	
Electric						
Futures and Options-NYMEX (net)	—	$—	$—	—	$—	$—
Physicals	246,729	(8,906)	(2,712)	74,764	(536)	(498)
Options - OTC	10,368	(133)	(69)	8,907	(43)	(56)
Swaps	11,289	(144)	(47)	180	(2)	(2)
	MMMBTU	(in millions)		MMMBTU	(in millions)	

Gas						
Futures and Options-NYMEX (net)	23,110	$(81)	$(11)	69,840	$(8)	$(5)
Physicals	442,309	(420)	(91)	301,271	(32)	(26)
Options - OTC	666,304	(934)	(306)	227,225	(55)	(37)
Swaps	4,616,178	(7,592)	(1,762)	2,601,644	(379)	(303)

AEP routinely enters into exchange traded futures and options transactions for electricity and natural gas as part of its wholesale trading operations. These transactions are executed through brokerage accounts with brokers who are registered with the Commodity Futures Trading Commission. Brokers require cash or cash related instruments to be deposited on these accounts as margin calls against the customer's open position. The amount of these deposits at December 31, 2000 and 1999 was $95 million and $25 million, respectively.

Credit and Risk Management — In addition to market risk associated with price movements, AEP is also subject to the credit risk inherent in its risk management activities. Credit risk refers to the financial risk arising from commercial transactions and/or the intrinsic financial value of contractual agreements with trading counter parties, by which there exists a potential risk of non-performance. The Company has established and enforced credit policies that minimize or eliminate this risk. AEP accepts as counter parties to forwards, futures, and other derivative contracts primarily those entities that are classified as Investment Grade, or those that can be considered as such due to the effective placement of credit enhancements and/or collateral agreements. Investment Grade is the designation given to the four highest debt rating categories (i.e., AAA, AA, A, BBB) of the major rating services, e.g., ratings BBB- and above at Standard & Poor's and Baa3 and above at Moody's. When adverse market conditions have the potential to negatively affect a counter party's credit position, the Company will require further enhancements to mitigate risk. Since the formation of the trading business in July of 1997, the Company has not experienced a significant loss due to the credit risk; furthermore, the Company does not anticipate any future material effect on its results of operations, cash flow or financial condition as a result of counter party non-performance.

Other Financial Instruments — Nuclear Trust Funds Recorded at Market Value — The trust investments for decommission and SNF disposal, reported in other assets, are recorded at market value. At December 31, 2000 and 1999 the fair values of the trust investments were $873 million and $795 million, respectively, and had a cost basis of $768 million and $696 million, respectively. The change in market value in 2000, 1999, and 1998 was a net unrealized holding gain of $6 million, $18 million, and $32 million, respectively.

CitiPower entered into several interest rate swap agreements for $425 million of borrowings under a credit facility. The swap agreements involve the exchange of floating-rate for fixed-rate interest payments. Interest is recognized currently based on the fixed rate of interest resulting from use of these swap agreements. Market risks arise from the movements in interest rates. If counter parties to an interest rate swap agreement were to default on contractual payments, CitiPower could be exposed to increased costs related to replacing the original agreement. However, CitiPower does not anticipate non-performance by any counter party to any interest rate swap in effect as of December 31, 2000. As of December 31, 2000, CitiPower was a party to interest rate swaps having an aggregate notional amount of $626 million, with $224 million maturing on December 31, 2003, and $201 million maturing on December 29, 2003, $201 million commencing on December 29, 2003 and maturing on December 30, 2005. The average fixed interest rate payable on the aggregate of the interest rate swaps is 5.84%. The average floating rate for interest rate swaps was 6.04% at December 31, 2000. The estimated fair value of the interest rate swaps, which represents the estimated amount CitiPower would receive to terminate the swaps at December 31, 2000, based on quoted interest rates, is a net receivable of less than a million dollars.

CitiPower entered into interest rate swap agreement for $112 million in January 2000, for the purpose of hedging a capital markets bond issue. The interest rate swap agreement exchanges a fixed-rate for a floating interest rate up to January 15, 2007. The $112 million interest rate swap agreement was terminated on December 18, 2000. The gain of $9 million earned upon termination of the swap agreement has been deferred and will be amortized through January 15, 2007.

The CSW UK Holdings Group (Group) entered into two currency swaps in 1996 in respect of two tranches of $200 million notes ("Yankee Bonds") repayable on August 1, 2001 and August 1, 2006. The swaps convert fixed rate semi-annual U.S. Dollar interest payments at 6.95% and 7.45% to fixed rate sterling. As a result of the swaps the effective fixed sterling interest rates, including fees, are 7.98% and 8.75%. The estimated fair value of these swaps at December 31, 2000 is a net payable of $1 million.

The Group also has an interest in two interest rate swaps entered into by its joint venture associate Power Asset Development Company Limited in 1998. The swaps convert floating rate interest payable on a $157 million bank project finance borrowing, maturing in 2021, to 6.00% fixed rate. The estimated fair value of these swaps at December 31, 2000 is a net payable of $4 million of which the Group's interest is $2 million.

In addition, at December 31, 2000, the Group has an interest in a currency swap and an interest rate swap entered into by another joint venture associate, South Coast Power Limited. The estimated fair value of these swaps is a net receivable of $3 million of which the Group's share is $1 million.

In accordance with the debt covenants included in the financing provisions of its credit facility, CitiPower must hedge at least 80% of its energy purchase requirements through energy trading derivative instruments entered into with market participants, predominantly generators. As of December 31, 2000, CitiPower had outstanding energy trading derivatives with a total contracted load of 10,144 GWH's. The maturities for these contracts range from three months to six years. Management's estimate of the fair value of these derivatives as of December 31, 2000 is $7 million in excess of net contract value.

SEEBOARD manages its energy purchase costs through energy trading derivative instruments entered into with market participants. The Company buys derivative instruments to hedge purchase costs only and does not enter into any speculative trades. As of December 31, 2000, SEEBOARD had outstanding energy trading derivatives with a total contracted volume of 14,059 GWH's excluding Medway Power Limited. These contracts have maturities in the range of 1 to 27 months. In addition SEEBOARD has a 15 year contract with Medway Power Limited which owns and operates a 675 MW combined cycle gas generating station. SEEBOARD also has a 37.5% equity interest in Medway Power Limited. There are 29,025 GWH remaining under the contract which has 10 years and 9 months to run. Management's estimate of the fair value of these derivatives as of December 31, 2000 is $132 million below net contract value.

16. Income Taxes:

The details of income taxes as reported are as follows:

	2000	1999	1998
	Year Ended December 31, (in millions)		
Federal:			
Current	$ 766	$308	$492
Deferred	(237)	129	(43)
Total	529	437	449
State:			
Current	50	25	30
Deferred	(9)	—	—
Total	41	25	30
International:			
Current	6	3	14
Deferred	21	17	9
Total	27	20	23
Total Income Tax as Reported	$597	$482	$502

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

	2000	1999	1998
	Year Ended December 31, (in millions)		
Net Income	$267	$972	$975
Extraordinary Items (net of income tax $44 million in 2000 and $8 million in 1999)	35	14	—
Preferred Stock Dividends	11	19	19
Income Before Preferred Stock Dividends of Subsidiaries	313	1,005	994
Income Taxes	597	482	502
Pre-Tax Income	$910	$1,487	$1,496
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$319	$520	$524
Increase (Decrease) in Income Tax Resulting from the Following Items:			

Depreciation	77	71	67
Corporate Owned Life Insurance	247	2	(16)
Foreign Tax Credits	(31)	(63)	(49)
Investment Tax Credits (net)	(36)	(38)	(37)
Merger Transaction Costs	49	—	—
State Income Taxes	26	16	19
International	18	13	15
Other	(72)	(39)	(21)
Total Income Taxes as Reported	$597	$482	$502
Effective Income Tax Rate	65.5%	32.5%	33.6%

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

	December 31,	
	2000	1999
	(in millions)	
Deferred Tax Assets	$ 1,248	$ 1,241
Deferred Tax Liabilities	(6,123)	(6,391)
Net Deferred Tax Liabilities	$(4,875)	$(5,150)
Property Related Temporary Differences	$(3,935)	$(4,109)
Amounts Due From Customers For Future Federal Income Taxes	(415)	(437)
Deferred State Income Taxes	(251)	(220)
Regulatory Assets Designated for Securitization	(332)	(332)
All Other (net)	58	(52)
Net Deferred Tax Liabilities	$(4,875)	$(5,150)

The Company has settled with the IRS all issues from the audits of its consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1999 are presently being audited by the IRS. 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.

17. Supplementary Information:

	Year Ended December 31,		
	2000	1999	1998
	(in millions)		
Purchased Power - Ohio Valley Electric Corporation (44.2% owned by AEP System)	$86	$64	$43
Cash was paid for:			
Interest (net of capitalized amounts)	$842	$979	$859
Income Taxes	$449	$270	$540
Noncash Investing and Financing Activities:			
Acquisitions under Capital Leases	$118	$80	$119
Assumption of Liabilities Related to Acquisitions	—	—	$152

18. Leases:

Leases of property, plant and equipment are for periods of up to 35 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 charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for non-regulated property are accounted for as if the assets were owned and financed. The components of year ended December 31, rental costs are as follows:

	Year Ended December 31,		
	2000	1999	1998
	(in millions)		
Lease Payments on Operating Leases	$216	$247	$257
Amortization of Capital Leases	121	97	91
Interest on Capital Leases	38	35	37
Total Lease Rental Costs	$375	$379	$385

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31,	
	2000	1999
	(in millions)	
Property, Plant and Equipment:		
Production	$ 42	$ 46

Distribution	151	106
Other:		
Nuclear Fuel (net of amortization)	90	108
Mining and Other Assets	619	612
Total Property, Plant and Equipment	902	872
Accumulated Amortization	288	262
Net Property, Plant and Equipment	$614	$610
Obligations Under Capital Leases:		
Noncurrent Liability	$419	$510
Liability Due Within One Year	195	100
Total	$614	$610

Future minimum lease payments consisted of the following at December 31, 2000:

	Capital Leases	Noncancellable Operating Leases
	(in millions)	
2001	$129	$244
2002	99	236
2003	81	235
2004	63	235
2005	48	243
Later Years	397	3,090
Total Future M Minimum Lease Payments	817 (a)	$4,283
Less Estimated Interest Element	293	
Estimated Present Value of Future Minimum Lease Payments	524	
Unamortized Nuclear Fuel	90	
Total	$614	

(a) Minimum lease payments do not include nuclear fuel payments. The payments are paid in proportion to heat produced and carrying charges on the unamortized nuclear fuel balance. There are no minimum lease payment requirements for leased nuclear fuel.

19. Lines of Credit and Commitment Fees:

The AEP System uses short-term debt, primarily commercial paper, to meet fluctuations in working capital requirements and other interim capital needs. AEP has established a money pool to coordinate short-term borrowings for certain subsidiaries and also incurs borrowings outside the money pool for other subsidiaries. As of December 31, 2000, AEP had revolving credit facilities totaling $3.5 billion to backup its commercial paper program. At December 31, 2000, AEP had $2.7 billion outstanding in short-term borrowings. The maximum amount of such short-term borrowings outstanding during the year, which had a weighted average interest rate for the year of 7.5% was $2.7 billion during December 2000.

AEP Credit, which does not participate in the money pool, issues commercial paper on a stand-alone basis. At December 31, 2000, AEP Credit had a $2.0 billion unsecured revolving credit agreement to back up its commercial paper program, which had $1.2 billion outstanding. The maximum amount of such commercial paper outstanding during the year, which had a weighted average interest rate for the year of 6.6% was $1.5 billion during September 2000.

Outstanding short-term debt consisted of:

	December 31,	
	2000	1999
	(in millions)	
Balance Outstanding:		
Notes Payable	$193	$232
Commercial Paper	4,140	2,780
Total	$4,333	$3,012

20. Unaudited Quarterly Financial Information:

	2000 Quarterly Periods Ended			
(In Millions - Except Per Share Amounts)	March 31	June 30	Sept. 30	Dec. 31
Operating Revenues	$3,021	$3,169	$3,915	$3,589
Operating Income	428	308	873	417
Income (Loss) Before Extraordinary Items	140	(18)	403	(223)
Net Income (Loss)	140	(9)	359	(223)
Earnings (Loss) per Share	0.43	(0.03)	1.11	(0.68)

Fourth quarter 2000 earnings decreased $415 million from the prior year. The decrease was primarily due to various unfavorable items including: a ruling disallowing interest deductions claimed by AEP relating to its COLI program of $319 million; $35 million of the Cook Plant restart costs; and a $30 million writedown for the proposed sale of Yorkshire. Additionally, the fourth quarter of 1999 includes a $33 million gain on the sale of Sweeney in October.

(In Millions - Except Per Share Amounts)	1999 Quarterly Periods Ended March 31	June 30	Sept. 30	Dec. 31
Operating Revenues	$2,902	$2,963	$3,528	$3,014
Operating Income	525	552	802	446
Income Before Extraordinary Items	195	190	403	198
Net Income	195	190	395	192
Earnings per Share	0.61	0.59	1.23	0.60

21. Trust Preferred Securities:

The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of CPL, PSO and SWEPCo were outstanding at December 31, 2000 and December 31, 1999. They are classified on the balance sheets as certain subsidiaries Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of such subsidiaries. The Junior Subordinated Debentures mature on April 30, 2037. CPL reacquired 60,000 trust preferred units during 2000.

Business Trust	Security	Units issued/ outstanding at 12/31/00	2000 Amount (millions)	1999 Amount (millions)	Description of Underlying Debentures of Registrant
CPL Capital I	8.00%, Series A	5,940,000	$149	$150	CPL, $153 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	75	75	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	7.875%, Series A	4,400,000	110	110	SWEPCO, $113 million, 7.875%, Series A
		13,340,000	$334	$335	

Each of the business trusts is treated as a 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 their subordinated debentures, each of the parent companies has also agreed to a security obligation which represents a full and unconditional guarantee of its capital trust obligation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

	December 31, 2000			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(g)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	614,608	$ 61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	(d)	1,950,000	333,100	$ 33
6.02% - 6-7/8% (c)	(e)	1,650,000	513,450	52
7% (f)	(f)	250,000	150,000	15
Total Subject to Mandatory Redemption (c)				$100

	December 31, 1999			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(g)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	629,671	$ 63
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	(d)	1,950,000	343,100	$ 34
6.02% - 6-7/8% (c)	(e)	1,950,000	597,950	60
7% (f)	(f)	250,000	250,000	25
Total Subject to Mandatory Redemption (c)				$119

NOTES TO SCHEDULE OF CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

(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, 2000 the subsidiaries had 13,592,750, 22,200,000 and 7,713,495 shares of $100, $25 and no par value preferred stock, respectively, 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. The sinking fund provisions of the series subject to mandatory redemption aggregate (after deducting sinking fund requirements) of $5 million in 2002, $12 million in 2003, $12 million in 2004 and $2 million in 2005.

(d) Not callable prior to 2003; after that the call price is $100 per share.

(e) Not callable prior to 2000; after that the call price is $100 per share.

(f) With sinking fund.

(g) The number of shares of preferred stock redeemed is 209,563 shares in 2000, 1,698,276 shares in 1999 and 281,250 shares in 1998.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES

Maturity	Weighted Average Interest Rate	Interest Rates at December 31,		December 31,	
	December 31, 2000	2000	1999	2000	1999
				(in millions)	
FIRST MORTGAGE BONDS					
2000-2003	6.96%	5.91%-8.95%	5.25%-8.95%	$1,247	$ 1,621
2004-2008	6.97%	6-1/8%-8%	6-1/8%-8%	1,140	1,148
2020-2025	7.74%	6-7/8%-8.80%	6-7/8%-8.80%	1,104	1,172
INSTALLMENT PURCHASE CONTRACTS (a)					
2000-2009	5.53%	4.90%-7.70%	4.80%-7.70%	234	235
2011-2030	6.02%	4.875%-8.20%	3.332%-8.20%	1,447	1,477
NOTES PAYABLE (b)					
2000-2021	7.14%	6.20%-9.60%	5.8675%-9.60%	1,181	2,030
SENIOR UNSECURED NOTES					
2000-2004	6.99%	6.50%-7.45%	6.07%-7.45%	2,049	1,403
2005-2009	6.59%	6.24%-6.91%	6.24%-6.91%	475	488
2038	7.30%	7.20%-7-3/8%	7.20%-7-3/8%	340	340
JUNIOR DEBENTURES					
2025-2038	8.05%	7.60%-8.72%	7.60%-8.72%	620	620
YANKEE BONDS AND EURO BONDS					
2001-2006	8.51%	7.98%-8.875%	7.98%-8.875%	684	742
OTHER LONG-TERM DEBT (c)				280	300
Unamortized Discount (net)				(47)	(52)
Total Long-term Debt Outstanding (d)				10,754	11,524

Less Portion Due Within One Year	1,152	1,367
Long-term Portion	$9,602	$10,157

NOTES TO SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES

(a) 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.

(b) 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.

(c) Other long-term debt consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 8 of the Notes to Consolidated Financial Statements) and financing obligation under sale lease back agreements.

(d) Long-term debt outstanding at December 31, 2000 is payable as follows:

	Principal Amount (in millions)
2001	$1,152
2002	1,167
2003	1,628
2004	884
2005	616
Later Years	5,354
Total Principal Amount	10,801
Unamortized Discount	(47)
Total	$10,754

Management's Responsibility

The management of American Electric Power Company, Inc. is responsible for the integrity and objectivity of the information and representations in this annual report, including the consolidated financial statements. These statements have been prepared in conformity with accounting principles generally accepted in the U.S., using informed estimates where appropriate, to reflect the Company's financial condition and results of operations. The information in other sections of the annual report is consistent with these statements.

The Company's Board of Directors has oversight responsibilities for determining that management has fulfilled its obligation in the preparation of the consolidated financial statements and in the ongoing examination of the Company's established internal control structure over financial reporting. The Audit Committee, which consists solely of outside directors and which reports directly to the Board of Directors, meets regularly with management, Deloitte & Touche LLP — independent auditors and the Company's internal audit staff to discuss accounting, auditing and reporting matters. To ensure auditor independence, both Deloitte & Touche LLP and the internal audit staff have unrestricted access to the Audit Committee.

The consolidated financial statements have been audited by Deloitte & Touche LLP, whose report appears on the next page. The auditors provide an objective, independent review as to management's discharge of its responsibilities insofar as they relate to the fairness of the Company's reported financial condition and results of operations. Their audit includes procedures believed by them to provide reasonable assurance that the consolidated financial statements are free of material misstatement and includes an evaluation of the Company's internal control structure over financial reporting.

Independent Auditors' Report

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

We have audited the consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits. The consolidated financial statements give retroactive effect to the merger of American Electric Power Company, Inc. and its subsidiaries and Central and South West Corporation and its subsidiaries, which has been accounted for as a pooling of interests as described in Note 3 to the consolidated financial statements. We did not audit the consolidated balance sheet of Central and South West Corporation and its subsidiaries as of December 31, 1999, or the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for the years ended December 31, 1999 and 1998, which statements reflect total assets of $14,162,000,000 as of December 31, 1999, and total revenues of $5,537,000,000 and $5,482,000,000 for the years ended December 31, 1999 and 1998, respectively. Those consolidated statements, before the restatement described in Note 3, were audited by other auditors whose report, dated February 25, 2000, has been furnished to us, and our opinion, insofar as it relates to those amounts included for Central and South West Corporation and its subsidiaries for 1999 and 1998, is based solely on the report of such other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and its subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 and 1998 financial statements to give retroactive effect to the conforming change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

Deloitte & Touche LLP

Deloitte & Touche LLP
Columbus, Ohio
February 26, 2001

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SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the fiscal year ended December 31, 2000

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the transition period from ____________ to ____________

<TABLE>
<CAPTION>

COMMISSION FILE NUMBER	REGISTRANT; STATE OF INCORPORATION; ADDRESS AND TELEPHONE NUMBER
<S>	<C>
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporati 1 Riverside Plaza, Columbus, Ohio 43215 Telephone (614) 223-1000
0-18135	AEP GENERATING COMPANY (An Ohio Corporation) 1 Riverside Plaza, Columbus, Ohio 43215 Telephone (614) 223-1000
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation) 40 Franklin Road, Roanoke, Virginia 24011 Telephone (540) 985-2300
0-346	CENTRAL POWER AND LIGHT COMPANY (A Texas Corporation) 539 North Carancahua Street, Corpus Christi, Texas 78401-28 Telephone (361) 881-5300
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation) 1 Riverside Plaza, Columbus, Ohio 43215 Telephone (614) 223-1000
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation) One Summit Square, P. O. Box 60, Fort Wayne, Indiana 46801 Telephone (219) 425-2111
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation) 1701 Central Avenue, Ashland, Kentucky 41101 Telephone (800) 572-1141
1-6543	OHIO POWER COMPANY (An Ohio Corporation)

	301 Cleveland Avenue, S.W., Canton, Ohio 44701 Telephone (330) 456-8173
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation) 212 East 6th Street, Tulsa, Oklahoma 74119-1212 Telephone (918) 599-2000
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation) 428 Travis Street, Shreveport, Louisiana 71156-0001 Telephone (318) 673-3000
0-340	WEST TEXAS UTILITIES COMPANY (A Texas Corporation) 301 Cypress Street, Abilene, Texas 79601-5820 Telephone (915) 674-7000

</TABLE>

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

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SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

<TABLE>
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REGISTRANT	TITLE OF EACH CLASS
<S>	<C>
AEP Generating Company	None
American Electric Power Company, Inc.	Common Stock, $6.50 par value..
Appalachian Power Company	4-1/2% Cumulative Preferred Stock, Voting, no par value...................................... 8-1/4% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2026................ 8% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2027................ 7.20% Senior Notes, Series A, Due 2038....................... 7.30% Senior Notes, Series B, Due 2038.......................
Columbus Southern Power Company	8-3/8% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025................. 7.92% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2027.................
CPL Capital I	8.00% Cumulative Quarterly Income Preferred Securities, Series A, Liquidation Preference $2 per Preferred Security.....................................
Indiana Michigan Power Company	8% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2026................. 7.60% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2038.................
Kentucky Power Company	8.72% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025.................

Ohio Power Company	8.16% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025................
	7.92% Junior Subordinated Deferrable Interest Debentures Series B, Due 2027................
	7 3/8% Senior Notes, Series A, Due 2038.....................
PSO Capital I	8.00% Trust Originated Preferred Securities, Series A, Liquidation Preference $25 per Preferred Security..................
SWEPCo Capital I	7.875% Trust Preferred Securities, Series A, Liquidation amount $25 per Preferred Security..................................

</TABLE>

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SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

<TABLE>
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REGISTRANT	TITLE OF EACH CLASS
<S>	<C>
AEP Generating Company	None
American Electric Power Company, Inc.	None
Appalachian Power Company	None
Central Power and Light Company	4.00% Cumulative Preferred Sto
	4.20% Cumulative Preferred Sto
Columbus Southern Power Company	None
Indiana Michigan Power Company	4-1/8% Cumulative Preferred St
Kentucky Power Company None Ohio Power Company	4-1/2% Cumulative Preferred St
Public Service Company of Oklahoma	None
Southwestern Electric Power Company	4.28% Cumulative Preferred Sto
	4.65% Cumulative Preferred Sto
	5.00% Cumulative Preferred Sto
West Texas Utilities Company	None

</TABLE>

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	AGGREGATE MARKET VALUE OF VOTING AND NON-VOTING COMMON EQUITY HELD BY NON-AFFILIATES OF THE REGISTRANTS AT FEBRUARY 1, 2001	NUMB OF C OUT THE R FEBR
<S>	<C>	<C>
AEP Generating Company	None	($1,0
American Electric Power Company, Inc.	$13,853,503,196	32 ($6.5
Appalachian Power Company	None	1 (no
Central Power and Light Company	None	6 ($25
Columbus Southern Power Company	None	1 (no
Indiana Michigan Power Company	None	1 (no

Kentucky Power Company	None	1 ($50
Ohio Power Company	None	2 (no
Public Service Company of Oklahoma	None	9 ($15
Southwestern Electric Power Company	None	7 ($18
West Texas Utilities Company	None	5 ($25

</TABLE>

NOTE ON MARKET VALUE OF COMMON EQUITY HELD BY NON-AFFILIATES

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

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 [X]. No.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of 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. [X]

DOCUMENTS INCORPORATED BY REFERENCE

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DESCRIPTION

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Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2000:

AEP Generating Company
American Electric Power Company, Inc.
Appalachian Power Company
Central Power and Light Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company
West Texas Utilities Company

Portions of Proxy Statement of American Electric Power Company, Inc. for 2001 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2000

Portions of Information Statements of the following companies for 2001 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2000

Appalachian Power Company
Ohio Power Company

</TABLE>

THIS COMBINED FORM 10-K IS SEPARATELY FILED BY AEP GENERATING COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC., APPALACHIAN POWER COMPANY, CENTRAL POWER AND LIGHT COMPANY, COLUMBUS SOUTHERN POWER COMPANY, INDIANA MICHIGAN POWER COMPANY, KENTUCKY POWER COMPANY, OHIO POWER COMPANY, PUBLIC SERVICE COMPANY OF OKLAHOMA, SOUTHWESTERN ELECTRIC POWER COMPANY AND WEST TEXAS UTILITIES 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.

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GLOSSARY OF TERMS

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

<TABLE>
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ABBREVIATION OR ACRONYM	DEFINITION
<S>	<C>
AEGCo..	AEP Generating Company, an electric util
AEP	American Electric Power Company, Inc.
AEP System or the System......................	The American Electric Power System, an i and operated by AEP's electric utility
AFUDC..	Allowance for funds used during construc accounts as the net cost of borrowed f rate of return on other funds when so
APCo..	Appalachian Power Company, an electric u
Btu..	British thermal unit.
Buckeye..	Buckeye Power, Inc., an unaffiliated cor
C3..	C3 Communications, Inc.
CAA..	Clean Air Act.
CAAA..	Clean Air Act Amendments of 1990.
CCD Group..	CSPCo, CG&E and DP&L.
CERCLA..	Comprehensive Environmental Response, Co
CG&E..	The Cincinnati Gas & Electric Company, a
CO2..	Carbon dioxide.
Cook Plant..	The Donald C. Cook Nuclear Plant, owned
CPL..	Central Power and Light Company, an elec
CSPCo..	Columbus Southern Power Company, an elec
CSW..	Central and South West Corporation.
DOE..	United States Department of Energy.
DP&L..	The Dayton Power and Light Company, an u
East Zone Companies of AEP....................	APCo, CSPCo, I&M, KEPCo and OPCo.
EWG..	Exempt wholesale generator.
Federal EPA..	United States Environmental Protection A
FERC..	Federal Energy Regulatory Commission (an
FUCO..	Foreign utility company as defined by PU
I&M..	Indiana Michigan Power Company, an elect
IURC..	Indiana Utility Regulatory Commission.
KEPCo..	Kentucky Power Company, an electric util
NOx..	Nitrogen oxide.
NPDES..	National Pollutant Discharge Elimination
NRC..	Nuclear Regulatory Commission.
Ohio EPA..	Ohio Environmental Protection Agency.
OPCo..	Ohio Power Company, an electric utility

OVEC	Ohio Valley Electric Corporation, an ele CSPCo own a 44.2% equity interest.
PCBs	Polychlorinated biphenyls.
PSO	Public Service Company of Oklahoma, an e
PUCO	The Public Utilities Commission of Ohio.

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ABBREVIATION OR ACRONYM	DEFINITION
<S>	<C>
PUHCA	Public Utility Holding Company Act of 19
QF	Qualifying facility as defined in the Pu 1978.
RCRA	Resource Conservation and Recovery Act o
Rockport Plant	A generating plant, consisting of two 1, units, near Rockport, Indiana.
SEC	Securities and Exchange Commission.
SEEBOARD	SEEBOARD Group plc, Crawley, West Sussex
Service Corporation	American Electric Power Service Corporat
SO2	Sulfur dioxide.
SO2 Allowance	An allowance to emit one ton of sulfur d Amendments of 1990.
STP	South Texas Project Nuclear Generating P Bay City, Texas.
STPNOC	STP Nuclear Operating Company, a non-pro on behalf of its joint owners includin
SWEPCo	Southwestern Electric Power Company, an
TVA	Tennessee Valley Authority.
Vale	Empresa De Electricidade Vale Paranapane Company.
VEPCo	Virginia Electric and Power Company, an
Virginia SCC	Virginia State Corporation Commission.
West Virginia PSC	Public Service Commission of West Virgin
West Zone Companies of AEP	CPL, PSO, SWEPCo and WTU.
WTU	West Texas Utilities Company, an electri
Zimmer or Zimmer Plant	Wm. H. Zimmer Generating Station, common

</TABLE>

FORWARD-LOOKING INFORMATION

This report made by AEP and certain of its subsidiaries includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions and involve a number of risks and uncertainties. Among the factors that could cause actual results to differ materially from forward-looking statements are:

- Electric load and customer growth.

- Abnormal weather conditions.

- Available sources of and prices for coal and gas.

- Availability of generating capacity.

- The impact of the merger with CSW, including the ability of the combined companies to realize the synergies expected as a result of the combination.

- The timing of the implementation of AEP's restructuring plan.

- Risks related to energy trading and construction under contract.

- The speed and degree to which competition is introduced to our power generation business.

- The structure and timing of a competitive market for electricity and its impact on prices.

- The ability to recover net regulatory assets, other stranded costs and implementation costs in connection with deregulation of generation in certain states.

- New legislation and government regulations.

- The ability of AEP to successfully control its costs.

- The success of new business ventures.

- International developments affecting AEP's foreign investments.

- The effects of fluctuations in foreign currency exchange rates.

- The economic climate and growth in AEP's service and trading territories, both domestic and foreign.

- The ability of AEP to comply with or to challenge successfully new environmental regulations and to litigate successfully claims that AEP violated the CAA.

- Inflationary trends.

- Changes in electricity and gas market prices.

- Successful resolution of litigation regarding municipal franchise fees in Texas.

- Successful appeal of decision in connection with COLI litigation.

- Interest rates.

- Other risks and unforeseen events.

PART I ==

Item 1. BUSINESS

GENERAL

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company which owns, directly or indirectly, all of the outstanding common stock of its domestic electric utility subsidiaries and varying percentages of other subsidiaries. Substantially all of the operating revenues of AEP and its subsidiaries are derived from the furnishing of electric service. In addition, in recent years AEP has been pursuing various unregulated business opportunities worldwide as discussed in New Business Development.

The service area of AEP's domestic electric utility subsidiaries covers 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 subsidiaries are physically 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 electric utility subsidiaries of AEP, which do business as "American Electric Power," have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers.

At December 31, 2000, the subsidiaries of AEP had a total of 26,376 employees. AEP, as such, has no employees. The operating subsidiaries of AEP are:

APCo (organized in Virginia in 1926) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 909,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying electric power at wholesale to other electric utility companies and municipalities in those states and in Tennessee. At December 31, 2000, APCo and its wholly owned subsidiaries had 2,846 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 VEPCo. A comparatively small part of the properties and business of APCo is located in the northeastern end of the Tennessee Valley. 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.

CPL (organized in Texas in 1945) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 680,000 customers in southern Texas, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2000, CPL had 1,444 employees. Among the principal industries served by CPL are oil and gas extraction, food processing, apparel, metal refining, chemical and petroleum refining, plastics, and machinery equipment.

CSPCo (organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately

668,000 customers in Ohio, and in supplying electric power at wholesale to other electric utilities and to municipally owned distribution systems within its service area. At December 31, 2000, CSPCo had 1,264 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. Approximately 80% of CSPCo's retail revenues are derived from the Columbus area. 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.

I&M (organized in Indiana in 1925) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 565,000 customers in northern and eastern Indiana and southwestern Michigan, and in supplying electric power at wholesale to other electric utility companies, rural electric cooperatives and municipalities. At December 31, 2000, I&M had 2,965 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.

KEPCo (organized in Kentucky in 1919) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 172,000 customers in an area in eastern Kentucky, and in supplying electric power at wholesale to other utilities and municipalities in Kentucky. At December 31, 2000, KEPCo had 451 employees. In addition to its AEP System interconnections, KEPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KEPCo is also interconnected with TVA.

Kingsport Power Company (organized in Virginia in 1917) provides electric service to approximately 45,000 customers in Kingsport and eight neighboring communities in northeastern Tennessee. Kingsport Power Company has no generating facilities of its own. It purchases electric power distributed to its customers from APCo. At December 31, 2000, Kingsport Power Company had 62 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 696,000 customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying electric power at wholesale to other electric utility companies and municipalities. At December 31, 2000, OPCo and its wholly owned subsidiaries had 3,532 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.

PSO (organized in Oklahoma in 1913) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 499,000 customers in eastern and southwestern Oklahoma, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2000, PSO had 1,005 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.

SWEPCo (organized in Oklahoma in 1912) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 428,000 customers in northeastern Texas, northwestern Louisiana, and western Arkansas, and in supplying electric power at wholesale to other utilities, municipalities and

rural electric cooperatives. At December 31, 2000, SWEPCo had 1,243 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.

Wheeling Power Company (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 42,000 customers in northern West Virginia. Wheeling Power Company has no generating facilities of its own. It purchases electric power distributed to its customers from OPCo. At December 31, 2000, Wheeling Power Company had 75 employees.

WTU (organized in Texas in 1927) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 190,000 customers in west and central Texas, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2000, WTU had 718 employees. The principal industry served by WTU is agriculture. The territory served by WTU also includes several military installations and correctional facilities.

Another principal electric utility subsidiary of AEP is AEGCo, which was organized in Ohio in 1982 as an electric generating company. AEGCo sells power at wholesale to I&M and KEPCo. AEGCo has no employees.

See Item 2 for information concerning the properties of the subsidiaries of AEP.

The Service Corporation 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 the Service Corporation.

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, transportation and handling of fuel, sales or rentals of property and interest or dividend payments on the securities held by the companies' respective parents.

AEP-CSW MERGER

On June 15, 2000, CSW merged with and into a wholly owned merger subsidiary of AEP with CSW being the surviving corporation. The merger was pursuant to an Agreement and Plan of Merger, dated as of December 21, 1997, that AEP and CSW had entered into. As a result of the merger, each outstanding share of common stock, par value $3.50 per share, of CSW (other than shares owned by AEP or CSW) was converted into 0.6 of a share of common stock, par value $6.50 per share, of AEP.

CSW's four wholly-owned domestic electric utility subsidiaries are CPL, PSO, SWEPCo and WTU. CSW also has the following principal subsidiaries: CSW International, CSW Energy, SEEBOARD, AEP Credit, Inc., C3 and CSW Energy Services, Inc.

AEP intends to comply with the following conditions imposed by the FERC as part of the FERC's order approving the merger:

- Transfer operational control of AEP's east and west transmission systems to fully-functioning, FERC-approved regional transmission organizations by December 15, 2001. See Transmission Services for Non-Affiliates.

- Two interim transmission-related mitigation measures consisting of market monitoring and independent calculation and posting of available transmission capacity to monitor the operation of AEP's east transmission system.

- Divestiture of 550 MW of generating capacity comprised of 300 MW of capacity in the Southwest Power Pool (SPP) and 250 MW of capacity in the Electric Reliability Council of Texas (ERCOT). AEP must complete divestiture of the SPP capacity by

July 1, 2002. AEP has completed divestiture of the ERCOT capacity.

The FERC found that certain energy sales of SPP and ERCOT capacity would be reasonable and effective interim mitigation measures until completion of the required SPP and ERCOT divestitures. As required by the FERC, the proposed interim energy sales were in effect when the merger was consummated.

REGULATION

General

AEP and its subsidiaries are subject to the broad regulatory provisions of PUHCA administered by the SEC. The public utility subsidiaries' retail rates and certain other matters are subject to regulation by the public utility commissions of the states in which they operate. Such subsidiaries are also subject to regulation by the FERC under the Federal Power Act in respect of rates for interstate sale at wholesale and transmission of electric power, accounting and other matters and construction and operation of hydroelectric projects. I&M and CPL 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.

Possible Change to PUHCA

The provisions of PUHCA, administered by the SEC, regulate all aspects of a registered holding company system, such as the AEP System. PUHCA requires that the operations of a registered holding company system be limited 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 assets and intra-system transactions.

On June 20, 1995, the SEC released a report from its Division of Investment Management recommending a conditional repeal of PUHCA, including its limits on financing and on geographic and business diversification. Specific federal authority, however, would be preserved over access to the books and records of registered holding company systems, audit authority over registered holding companies and their subsidiaries and oversight over affiliate transactions. This authority would be transferred to the FERC. Following the report, legislation was introduced in Congress to repeal PUHCA and transfer certain federal authority to the FERC as recommended in the SEC report. Since 1997, such PUHCA repeal language has been part of broader legislation regarding changes in the electric industry. Such legislation, both as a separate bill and as part of broader electricity restructuring legislation, was reintroduced in 1999 and 2000. Legislative hearings were held but no PUHCA repeal legislation was passed by either the House of Representatives or Senate. It is expected that a number of bills contemplating PUHCA repeal separately and the restructuring of the electric utility industry will be introduced in the current Congress. See Competition and Business Change. If PUHCA is repealed, registered holding company systems, including the AEP System, will be able to compete in the changing industry without the constraints of PUHCA. Management of AEP believes that removal of these constraints would be beneficial to the AEP System.

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 been introduced in Congress to repeal PUHCA or modify its provisions governing intra-system transactions. The effect of repeal or amendment of PUHCA on AEP's intra-system transactions depends on whether the assurance of full cost recovery is eliminated immediately or phased in and whether it is eliminated for all intra-system transactions or only some. If the cost recovery assurance is eliminated immediately for all intra-system transactions, it could have a material adverse effect on results of operations and financial condition of AEP and OPCo. Current legislation grandfathers transactions legally authorized on the effective date of PUHCA repeal.

Conflict of Regulation

Public utility subsidiaries of AEP can be subject to regulation of the same subject matter by two or more jurisdictions. In such situations, it is possible that the decisions of such regulatory bodies may conflict or that the decision of one such body may affect the cost of providing service, and so the rates, in another jurisdiction. In a case involving OPCo, the U.S. Court of Appeals for the District of Columbia held that the determination of costs to be charged to associated companies by the SEC under PUHCA precluded the FERC from determining that such costs were unreasonable for ratemaking purposes. The U.S. Supreme Court also has held that a state commission may not conclude that a FERC approved wholesale power agreement is unreasonable for state ratemaking purposes. Certain actions that would overturn these decisions or otherwise affect the jurisdiction of the SEC and FERC are under consideration by the U.S. Congress and these regulatory bodies. Such conflicts of jurisdiction often result in litigation and, if resolved adversely to a public utility subsidiary of AEP, could have a material adverse effect on the results of operations or financial condition of such subsidiary or AEP.

CLASSES OF SERVICE

The principal classes of service from which the domestic electric utility subsidiaries of AEP derive revenues and the amount of such revenues (from kilowatt-hour sales) during the year ended December 31, 2000 are as follows:

<TABLE>
<CAPTION>

	AEP SYSTEM(a)	AEGCO
		(IN THOUSAN
<S>	<C>	<C>
Retail		
Residential	$3,517,058	$0
Commercial	2,451,068	0
Industrial	2,443,750	0
Miscellaneous	213,620	0
Total Retail	8,625,496	0
Wholesale (sales for resale)	1,795,041	228,304
Total from KWH Sales	10,420,537	228,304
Other Operating Revenues and Refunds	406,895	212
Total Electric Operating Revenues	$10,827,432	$228,516

</TABLE>

<TABLE>
<CAPTION>

	CPL	CSPCO
	(IN THOUSANDS)	
<S>	<C>	<C>
Retail		
Residential	$651,580	$473,986
Commercial	460,433	434,785
Industrial	370,161	145,326
Miscellaneous	49,204	18,176
Total Retail	1,531,378	1,072,273
Wholesale (sales for resale)	140,671	243,827
Total from KWH Sales	1,672,049	1,316,100
Other Operating Revenues and Refunds	99,128	42,250
Total Electric Operating Revenues	$1,771,177	$1,358,350

</TABLE>

<TABLE>
<CAPTION>

	I&M	KEPCO
		(IN THOUSA
<S>	<C>	<C>
Retail		
Residential	$340,484	$112,707
Commercial	269,650	62,431

Industrial	334,622	93,111	
Miscellaneous	6,689	950	
Total Retail	951,445	269,199	
Wholesale (sales for resale)	557,235	120,482	
Total from KWH Sales	1,508,680	389,681	
Other Operating Revenues and Refunds	41,907	20,722	
Total Electric Operating Revenues	$1,550,587	$410,403	$

</TABLE>

<TABLE>
<CAPTION>

<S>	SWEPCO (IN THOUSANDS) <C>	WTU <C>
Retail		
Residential	$328,873	$164,973
Commercial	219,318	97,583
Industrial	273,430	65,517
Miscellaneous	31,782	46,060
Total Retail	853,403	374,133
Wholesale (sales for resale)	240,792	150,986
Total from KWH Sales	1,094,195	525,119
Other Operating Revenues and Refunds	30,015	47,675
Total Electric Operating Revenues	$1,124,210	$572,794

</TABLE>

(a) Includes revenues of other subsidiaries not shown and elimination of intercompany transactions.

SALE OF POWER

AEP's electric utility subsidiaries own or lease generating stations with total generating capacity of 38,033 megawatts. See Item 2 for more information regarding the generating stations. They operate their generating plants as a single interconnected and coordinated electric utility system and, in the east zone, share the costs and benefits in the AEP System Power Pool. Most of the electric power generated at these stations is sold, in combination with transmission and distribution services, to retail customers of AEP's utility subsidiaries in their service territories. These sales are made at rates that are established by the public utility commissions of the state in which they operate. See Rates and

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Regulation. Some of the electric power is sold at wholesale to non-affiliated companies.

AEP System Power Pool

APCo, CSPCo, I&M, KEPCo 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, KEPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO2 Allowances associated with transactions under the Interconnection Agreement.

Power marketing and trading transactions (trading activities) are conducted by the AEP Power Pool and shared among the parties under the Interconnection Agreement. Trading activities involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and the trading of electricity 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. The regulated physical forward contracts are recorded on a net basis in the month when the contract settles.

In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

The following table shows the net credits or (charges) allocated among the parties under the Interconnection Agreement and Interim Allowance Agreement during the years ended December 31, 1998, 1999 and 2000:

<TABLE>
<CAPTION>

<S>	1998(a) <C>	1999(a) (IN THOUSANDS) <C>	2000(a) <C>
APCo..................	$(142,500)	$(89,100)	$(274,000)
CSPCo................	(146,800)	(184,500)	(250,400)
I&M..................	(86,100)	(61,700)	93,900
KEPCo................	34,000	23,700	(21,500)
OPCo.................	341,400	311,600	452,000

</TABLE>

(a) Includes credits and charges from allowance transfers related to the transactions.

CPL, PSO, SWEPCo, WTU, and AEP Service Corporation are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement). The CSW Operating Agreement requires the operating companies of the west zone to maintain specified 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 subsidiaries as capacity commitments. The CSW Operating Agreement also delegates to AEP Service Corporation the authority to coordinate the acquisition, disposition, planning, design and construction of generating units and to supervise the operation and maintenance of a central control center. The CSW Operating Agreement has been accepted for filing and allowed to become effective by the FERC.

Wholesale Sales of Power to Non-Affiliates

AEP's electric utility subsidiaries also sell electric power on a wholesale basis to non-affiliated electric utilities and power marketers. Such sales are either made by the AEP System Power Pool and then allocated among APCo, CSPCo, I&M, KEPCo and OPCo based on member-load-ratios or made by individual companies pursuant to various long-term power agreements.

Reference is made to the footnote to the financial statements entitled Commitments and Contingencies that is incorporated by reference in Item 8 for information with respect to AEP's long-term agreements to sell power.

TRANSMISSION SERVICES

AEP's electric utility subsidiaries own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 for more information regarding the transmission and distribution lines. AEP's electric utility subsidiaries

operate their transmission lines as a single interconnected and coordinated system and share the cost and benefits in the AEP System Transmission Pool. Most of the transmission and distribution services are sold, in combination with electric power, to retail customers of AEP's utility subsidiaries in their service territories. These sales are made at rates that are established by the public utility commissions of the state in which they operate. See Rates and Regulation. As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP System Transmission Pool

APCo, CSPCo, I&M, KEPCo 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." See Sale of Power.

The following table shows the net (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 1998, 1999 and 2000:

<TABLE>
<CAPTION>

	1998	1999	2000
		(IN THOUSANDS)	
<S>	<C>	<C>	<C>
APCo...........	$(2,400)	$(8,300)	$(3,400)
CSPCo..........	35,600	39,000	38,300
I&M............	(44,100)	(43,900)	(43,800)
KEPCo..........	(6,000)	(4,300)	(6,000)
OPCo...........	16,900	17,500	14,900

</TABLE>

CPL, PSO, SWEPCo, WTU, and AEP Service Corporation are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA establishes a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone operating subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the Open Access

Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone operating subsidiaries have delegated to AEP Service Corporation 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 west zone operating subsidiaries of revenues collected for transmission and ancillary services provided under the OATT. The TCA has been accepted for filing by the FERC effective as of January 1, 1997, and is the subject of proceedings commenced to consider the reasonableness of its terms and conditions.

Transmission Services for Non-Affiliates

AEP's electric utility subsidiaries and other System companies also provide transmission services for non-affiliated companies.

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 which 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 Open Access Same-time Information System (OASIS) which electronically posts transmission information such as available capacity and prices, and require utilities to comply with Standards of Conduct which prohibit utilities' system operators from providing non-public transmission information to the utility's merchant 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 regional transmission organizations (RTOs), entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals.

On July 9, 1996, the AEP System companies filed a tariff conforming with the FERC's pro-forma transmission tariff.

During 1998 and 1999 AEP engaged in discussions with Consumers Energy Company, FirstEnergy Corp., Detroit Edison Company and VEPCo regarding the development of the Alliance RTO which may take the form of an ISO or an independent transmission company (Transco), depending upon the occurrence of certain conditions. The Transco, if formed, would operate transmission assets that it would own, and also would operate other owners' transmission assets on a contractual basis. In 1999, these companies filed with the FERC a proposal to form the RTO. In December 1999, the FERC approved the Alliance RTO, conditioned upon certain changes to the proposal relating to governance of the RTO, resolution of intra-RTO conflicts and establishment of a rate structure. On January 24, 2001, the FERC approved the compliance filing made by the Alliance RTO in September 2000 and generally accepted the responses to the changes proposed in the December 1999 FERC order. The January 2001 FERC order also directed the Alliance companies to file their actual rates no later than 120 days prior to the commencement of operations by the Alliance RTO.

COORDINATION OF EAST AND WEST ZONE OPERATING SUBSIDIARIES

AEP's System Integration Agreement provides for the integration and coordination of AEP's east and west zone operating subsidiaries, joint dispatch of generation within the AEP System, and the distribution, between the two operating zones, of costs and benefits associated with the System's generating plants. It is designed to function as an umbrella agreement in addition to the AEP Interconnection Agreement and the CSW Operating Agreement, each of which will continue to control the distribution of costs and benefits within each zone.

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

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

OVEC

AEP, CSPCo and several unaffiliated utility companies jointly own OVEC, which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio, owned by the DOE. The aggregate equity participation of AEP and CSPCo in OVEC is 44.2%. The DOE demand under OVEC's power agreement, which is subject to change from time to time, is 800,000 kilowatts. On April 1, 2001, it is scheduled to decrease to approximately 600,000 kilowatts. 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. APCo, CSPCo, I&M and OPCo, as sponsoring companies, are entitled to receive from OVEC, and are obligated to pay for, the power not required by DOE, which averaged 42.1% in 2000. On September 29, 2000, DOE issued a notice of cancellation of the power agreement. DOE will therefore not be entitled to any OVEC capacity beyond August 31, 2001. The sponsoring companies will be entitled to all OVEC capacity in proportion to their power participation ratios (approximately 2,200MW) beginning September 1, 2001.

BUCKEYE

Contractual arrangements among OPCo, Buckeye and other investor-owned electric utility companies in Ohio provide for the transmission and delivery, over facilities of OPCo and of other investor-owned utility companies, of power generated by the two units at the Cardinal Station

owned by Buckeye and back-up power to which Buckeye is entitled from OPCo under such contractual arrangements, to facilities owned by 25 of the rural electric cooperatives which operate in the State of Ohio at 331 delivery points. Buckeye is entitled under such arrangements 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 December 22, 2000, was recorded at 1,304,134 kilowatts.

In January 2000, OPCo and National Power Cooperative, Inc. (NPC), an affiliate of Buckeye, entered into an agreement, subject to specified conditions, relating to construction and operation of a 510 mw gas-fired electric generating peaking facility to be owned by NPC. From the commercial operation date (expected in early 2002) until the end of 2005, OPCo will be entitled to the power generated by the facility, and responsible for the fuel and other costs of the facility. 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. OPCo will also provide certain back-up power to NPC. AEP Pro Serv, Inc. will provide engineering, procurement and construction for the facility.

CERTAIN INDUSTRIAL CUSTOMERS

Century Aluminum of West Virginia, Inc. (formerly Ravenswood Aluminum Corporation), operates a major aluminum reduction plant in the Ohio River Valley at Ravenswood, West Virginia. The power requirement of such plant presently is approximately 357,000 kilowatts. OPCo is providing electric service pursuant to a contract approved by the PUCO for the period July 1, 1996 through July 31, 2003.

AEGCO

Since its formation in 1982, AEGCo's business has consisted of the ownership and financing of its 50% interest in 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 KEPCo pursuant to unit power agreements. Pursuant to these unit power agreements, AEGCo is entitled to recover its full cost of service from the purchasers and will be entitled to recover future increases in such costs, including increases in fuel and capital costs. See Unit Power Agreements. Pursuant to a capital funds agreement, AEP has agreed to provide cash capital contributions, or in certain circumstances subordinated loans, to AEGCo, to the extent necessary to enable AEGCo, among other things, to provide its proportionate share of funds required to permit continuation of the commercial operation of the Rockport Plant and 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. See Capital Funds Agreement.

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. 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) 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 FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the date that the last of the lease terms of Unit 2 of the Rockport Plant has expired unless extended in specified circumstances.

Pursuant to an assignment between I&M and KEPCo, and a unit power agreement between KEPCo and AEGCo, AEGCo sells KEPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KEPCo 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 KEPCo unit power agreement expires on December 31, 2004.

Capital Funds Agreement

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.

SEASONALITY

Sales of electricity by the AEP System tend to increase and decrease because of the use of electricity by residential and commercial customers for cooling and heating and relative changes in temperature.

FRANCHISES

The operating companies of the AEP System hold franchises to provide electric service in various municipalities in their service areas. 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.

COMPETITION AND BUSINESS CHANGE

General

The public utility subsidiaries of AEP, like many other electric utilities, have traditionally provided electric generation and energy delivery, consisting of transmission and distribution services, as a single product to their retail customers. Proposals are being made and legislation has been enacted in Arkansas, Michigan, Ohio, Oklahoma, Texas, Virginia and West Virginia that would also require electric utilities to sell distribution services separately. These measures generally allow competition in the generation and sale of electric power, but not in its transmission and distribution.

Competition in the generation and sale of electric power will require resolution of complex issues, including who will pay for the unused generating plant of, and other stranded costs incurred by, the utility when a customer stops buying power from the utility; will all customers have access to the benefits of competition; how will the rules of competition be established; what will happen to conservation and other regulatory-imposed programs; how will the reliability of the transmission system be ensured; and how will the utility's obligation to serve be changed. As competition in generation and sale of electric power is instituted, the public utility subsidiaries of AEP believe that they have a favorable competitive position because of their relatively low costs. If stranded costs are not recovered from customers, however, the public utility subsidiaries of AEP, like all electric utilities, will be required by existing accounting standards to recognize any stranded investment losses.

Reference is made to Management's Discussion and Analysis of Results of Operations and Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters and the footnote to the financial statements entitled Industry Restructuring incorporated by reference in Items 7 and 8, respectively, for further information with respect to competition and business change.

AEP Position on Competition

AEP favors freedom for customers to purchase electric power from anyone that they choose. Generation and sale of electric power would be in the competitive marketplace. To facilitate reliable, safe and efficient service, AEP supports creation of independent system operators to operate the transmission system in a region of the United States. AEP's working model for industry restructuring envisions a progressive transition to full customer

choice. Implementation of these measures would require legislative changes and regulatory approvals.

The legislatures and/or the regulatory commissions in many states, including some in AEP's service territory, are considering or have adopted "retail customer choice" which, in general terms, means the transmission by an electric utility of electric power generated by an entity of the customer's choice over its transmission and distribution system to a retail customer in such utility's service territory. A requirement to transmit directly to retail customers would have the result of permitting retail customers to purchase electric power, at the election of such customers, not only from the electric utility in whose service area they are located but from another electric utility, an independent power producer or an intermediary, such as a power marketer. Although AEP's power generation would have competitors under some of these proposals, its transmission and distribution would not. If competition develops in retail power generation, the public utility subsidiaries of AEP believe that they should have a favorable competitive position because of their relatively low costs.

Legislation to provide for retail competition among electric energy suppliers has been introduced in both the U.S. Senate and House of Representatives.

Wholesale

The public utility subsidiaries of AEP, like the electric industry generally, face increasing competition to sell available power on a wholesale basis, primarily to other public utilities and also to power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market (a) through amendments to PUHCA, facilitating the ownership and operation of generating facilities by "exempt wholesale generators" (which may include independent power producers as well as affiliates of electric utilities) and (b) through amendments to the Federal Power Act, authorizing the FERC under certain conditions to order utilities which own transmission facilities to provide wholesale transmission services for other utilities and entities generating electric power. The principal factors in competing for such sales are price (including fuel costs), availability of capacity and reliability of service. The public utility subsidiaries of AEP believe that they maintain a favorable competitive position on the basis of all of these factors. However, because of the availability of capacity of other utilities and the lower fuel prices in recent years, price competition has been, and is expected for the next few years to be, particularly important.

FERC orders 888 and 889, issued in April 1996, provide that utilities must functionally unbundle their transmission services, by requiring them to use their own tariffs in making off-system and third-party sales. See Transmission Services. The public utility subsidiaries of AEP have functionally separated their wholesale power sales from their transmission functions, as required by orders 888 and 889.

Retail

The public utility subsidiaries of AEP generally (except in Ohio) have the exclusive right to sell electric power at retail within their service areas, with the exception of Virginia and Texas beginning in 2002 and Ohio. However, they do 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 self-generation, the public utility subsidiaries of AEP believe that they maintain a favorable competitive position on the basis of all of these factors. 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 companies in the United States, including those served by the AEP System. Such industrial companies have requested price reductions from their suppliers, including their

suppliers of electric power. In addition, industrial companies which 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, various off-peak or interruptible supply options and believe that, as low cost suppliers of electric power, they should be less likely to be materially adversely affected by this competition and may be benefited by attracting new industrial customers to their service territories.

AEP Restructuring Plan

As a result of deregulating legislation that has been enacted or is being considered in most of the states in which the AEP public utility subsidiaries provide service, AEP has reassessed the corporate ownership of its public utility subsidiaries' assets. Deregulating legislation in some of the states requires the separation of generation assets from transmission and distribution assets. On November 1, 2000, AEP filed with the SEC under PUHCA for approval of a restructuring plan in part to meet the requirements of this legislation.

AEP's restructuring plan is designed to align its legal structure and business activities with the requirements of deregulation. AEP's plan contemplates the formation of two first tier subsidiaries that would hold the following public utility assets:

- A subsidiary would hold the assets of (i) public utility subsidiaries that remain subject to regulation by at least one state utility commission and (ii) foreign utility subsidiaries subject to regulation as to rates or tariffs. AEP intends for this subsidiary ultimately to hold all transmission and distribution assets.

- A subsidiary would hold public utility and non-utility subsidiaries that derive their revenues from competitive activity.

AEP intends for this subsidiary to ultimately hold all generation assets not subject to regulation.

NEW BUSINESS DEVELOPMENT

AEP has expanded its business to non-regulated energy activities through several subsidiaries, including AEP Energy Services, Inc. (AEPES), AEP Resources, Inc. (Resources), AEP Pro Serv, Inc. (formerly AEP Resources Service Company) (Pro Serv) and AEP Communications, LLC (AEP Communications).

Wholesale Business Operations

Various AEP subsidiaries, including AEPES, engage in wholesale business operations that focus primarily upon the following activities:

- Trade and market energy commodities, including electric power, natural gas, natural gas liquids, oil, coal, and SO2 allowances in North America and Europe.

- Provide price-risk management services and liquidity through a variety of energy-related financial instruments, including exchange-traded futures and over-the-counter forward, option, and swap agreements.

- Enter into long-term transactions to buy or sell capacity, energy, and ancillary services of electric generating facilities, either existing or to be constructed, at various locations in North America and Europe.

- Optimize trading and marketing through a diversified portfolio of owned assets and structured third party arrangements, including:

  - Power generation facilities.

  - Natural gas pipeline, storage and processing facilities.

  - Coal mines and related facilities.

  - Other transportation and fuel supply related assets.

- Acquire, develop, engineer, construct, operate and maintain owned and third party exempt wholesale generation and cogeneration facilities and ancillary energy-related assets.

AEP's subsidiaries are engaged in the engineering and construction for third parties of three power plants in the U. S. with a capacity of 1,910 MW. These plants, which are listed below, will be natural gas-fired facilities that are scheduled to be completed from 2001 to 2003. These projects synchronize the wholesale business through the integration of trading, marketing, engineering, construction and operations.

- AEP subsidiaries reached agreement with The Dow Chemical Company to construct a 900MW cogeneration facility in Louisiana. Commercial operation is expected in 2003.

- AEP subsidiaries reached agreement with Buckeye (an Ohio electric cooperative) to construct and operate a 510 MW peaking facility in Ohio. This agreement entitles AEP to 100% of the facility's capacity and energy in the upfront operating years through 2005. Commercial operation is expected in 2002.

- AEP subsidiaries reached agreement with Twelvepole Creek, LLC, a subsidiary of Columbia Electric, which was subsequently acquired by Orion Power Holdings, Inc., to engineer, procure and construct a 500 MW peaking facility in West Virginia. Commercial operation is expected in May 2001.

Houston Pipe Line Company: AEP subsidiaries reached agreement to acquire Houston Pipe Line Company (HPL) and its Bammel Storage Facility (one of the largest natural gas storage facilities in North America). HPL is a Texas intrastate pipeline and, along with Resources' midstream gas assets discussed below which were acquired in 1998, will provide a daily gas capacity of approximately 3.5 billion cubic feet, more than 6,400 miles of natural gas pipeline and a total storage capacity of approximately 128 billion cubic feet of high injection and withdrawal capabilities.

ICEX: AEP subsidiaries reached agreement to participate and to make an equity investment in a new internet-based electronic trading system Intercontinental Exchange, L.L.C. (ICEX) that enables participants to initiate, negotiate, and execute trades in the crude oil, natural gas, and spot and forward energy markets. Other investors include global energy companies and leading investment banking firms. This interest, along with an earlier investment in Altra Energy Technologies, Inc., provides additional liquidity trading points for the wholesale trading and marketing platform.

CSW Energy: CSW Energy presently owns interests in operating power projects located in Colorado, Florida and Texas. In addition to these projects, CSW Energy has other projects in various stages of development.

- CSW Energy has entered into an agreement with Eastman Chemical Company to construct and operate a 440 MW cogeneration facility in Longview, Texas. This facility will be known as the Eastex Cogeneration Project. Construction of the facility began in the fourth quarter of 1999, with expected operation in the second or third quarter of 2001. Excess electricity generated by the plant will be sold in the wholesale market.

- In October 1999, GE Capital Structured Finance Group purchased 50% of the equity ownership of Sweeny Cogeneration Limited Partnership. CSW Energy's after-tax earnings from the proceeds of the transaction were approximately $33 million. The agreement between CSW Energy and GE Capital Structured Financial Group provides for additional payments to CSW Energy subject to completion of a planned expansion of the Sweeny cogeneration facility, which may be operational in the second quarter of 2001.

CSW International: CSW International currently holds investments in the United Kingdom, Mexico and South America.

CSW International and its 50% partner, Scottish Power plc, have entered into a joint venture to construct and operate the South Coast Power Project, a 400 MW combined cycle gas turbine power station in Shoreham, United Kingdom. CSW International has guaranteed approximately Pound Sterling 19 million of the

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Pound Sterling 190 million construction financing. Both the guarantee and the construction financing are denominated in pounds sterling. The U. S. dollar equivalent at December 29, 2000 would be $28.4 million and $284.1 million respectively, using a conversion rate of Pound Sterling 1.00 equals $1.4953. Construction of the project began in March 1999, and commercial operation has begun though it is not yet running at full capacity.

Through November 1999, CSW International had purchased a 36% equity interest in Vale for $80 million. In 1998, CSW International also extended $100 million of debt convertible into equity in Vale. In December 1999, CSW International converted $69 million of that $100 million of debt into equity, thereby raising its equity interest in Vale to 44%. CSW International anticipates converting the remaining debt and accrued interest to equity in Caiua, a subsidiary of Vale, on December 1, 2001.

CSW International invested $110 million from September through November 1997 for 5% of the common stock of Gener, a Chilean electric company. This investment was sold in December 2000 for $67 million.

Resources

Resources' primary business is development of, and investment in, exempt wholesale generators, foreign utility companies, qualifying cogeneration facilities and other energy-related domestic and international investment opportunities and projects. Resources has business development offices in London; Beijing; Columbus, Ohio; Sydney and Washington D.C.

Resources also indirectly owns CitiPower Pty., an electric distribution and retail sales company in Victoria, Australia. CitiPower serves approximately 250,000 customers in the city of Melbourne. With about 3,100 miles of distribution lines in a service area that covers approximately 100 square miles, CitiPower distributes about 4,800 gigawatt-hours annually.

Resources' indirect subsidiary, AEP Pushan Power LDC, has a 70% interest in Nanyang General Light Electric Co., Ltd. (Nanyang Electric), a joint venture organized to develop and build two 125 megawatt coal-fired generating units near Nanyang City in the Henan Province of The Peoples Republic of China. Nanyang Electric was established in 1996 by AEP Pushan Power LDC, Henan Electric Power Development Co. (15% interest) and Nanyang City Hengsheng Energy Development Company Limited (formerly Nanyang Municipal Finance Development Co.) (15% interest). Unit 1 went into service in February 1999 and Unit 2 went into service in June 1999. Resources' share of the total cost of the project of $185,000,000 was approximately $110,000,000.

In December 1999, Resources contributed $47,000,000 to acquire a 50% interest in the Bajio power project in Mexico. The Bajio project is a 600 megawatt natural gas-fired, combined cycle plant and related assets located approximately 160 miles from Mexico City. Bechtel Power Corporation, an affiliate of Resources' partner (InterGen), will build the facility, which is estimated to cost $430,000,000. Approximately 80% of the project costs will be provided by third party debt, some of which will be supported by letters of credit issued on behalf of Resources. The facility will be operated and managed by one or more companies jointly owned by Resources and InterGen. Bajio has a 25-year contract to sell 495 megawatts of the plant's output to Mexico's federally owned electric system; the remainder is expected to be sold to industrial customers in the region. The Bajio project was approximately 60% completed as of December 31, 2000 and construction is expected to be completed in the fall of 2001.

Resources, through AEP Resources Australia Pty., Ltd., a special purpose subsidiary of Resources, owns a 20% interest in Pacific Hydro Limited. Pacific Hydro is principally engaged in the development and operation of, and ownership of interests in, hydroelectric facilities in the Asia Pacific region. Currently, Pacific Hydro has interests in six hydroelectric units and one wind farm unit that operate or are under construction in Australia and the Philippines. The hydroelectric facilities in which Pacific Hydro had interests as of December 31, 2000 (including those under construction) had total design capacity of approximately 181 megawatts.

Resources owns midstream gas assets, including:

- A 2,000-mile intrastate pipeline system in Louisiana.
- Four natural gas processing plants that straddle the pipeline.
- A ten billion cubic foot underground natural gas storage facility directly connected to the Henry Hub, the most active gas trading area in North America.

The pipeline and storage facilities are interconnected to 15 interstate and 23 intrastate pipelines.

U. K. Electric: Resources and another AEP subsidiary have a 50% interest in Yorkshire Electric Group plc (Yorkshire Electricity) with an indirect wholly-owned subsidiary of Xcel Energy, Inc. Yorkshire Electricity is a United Kingdom independent regional electricity company. It is principally engaged in the supply and distribution of electricity. Yorkshire Electricity has two million distribution customers in its authorized service territory which is comprised of 3,860 square miles and located centrally in the east coast of England.

In February 2001, AEP entered into an agreement to sell its 50% interest in Yorkshire. The sale is anticipated to be completed in the second quarter of 2001.

SEEBOARD, a wholly-owned subsidiary of CSW International, is one of the 12 regional electricity companies formed as a result of the restructuring and subsequent privatization of the United Kingdom electricity industry in 1990. CSW acquired indirect control of SEEBOARD in April 1996. SEEBOARD's principal businesses are the distribution and supply of electricity. In addition, SEEBOARD is engaged in other businesses, including gas supply, electricity generation, and electrical contracting. SEEBOARD's service area covers approximately 3,000 square miles in Southeast England. The area has a population of approximately 4.7 million people with significant portions of the area, such as south London, having a high population density.

In a joint venture, SEEBOARD Powerlink won a 30-year contract for $1.6 billion to operate, maintain, finance and renew the high-voltage power distribution network of the London Underground, the largest metropolitan rail system in the world. SEEBOARD's partners in the Powerlink consortium are an international electrical engineering group and an international cable and construction group.

On June 30, 1999, SEEBOARD purchased the 50% interest in Beacon Gas held by BP Amoco. Beacon Gas was a joint venture between SEEBOARD and BP Amoco set up for the supply of gas.

Pro Serv

Pro Serv offers engineering, construction, project management and other consulting services for projects involving transmission, distribution or generation of electric power both domestically and internationally.

AEP Communications

AEP Communications markets wholesale, high capacity, fiber optic services, colocation, and wireless tower infrastructure services under the C3 brand. In addition to expanding its fiber optic network during 2000, AEP Communications joined with several other energy and telecommunications companies to form AFN Communications, LLC. (AFN). AFN is a super regional telecommunications company that provides long haul fiber optic capacity to competitive local exchange carriers, wireless carriers and long distance companies. AFN does business in New York, Pennsylvania, Virginia, West Virginia, Ohio, Indiana, Michigan, Illinois, and Kentucky, with plans to expand nationally, and has approximately 10,000 route miles of fiber optic network. C3, an entity that was acquired through the merger with CSW, is engaged in providing fiber optic and collocation services in Texas, Louisiana, Oklahoma, Arkansas, and Kansas. C3 does business as C3 Networks and has approximately 5,300 route miles of fiber optic network. AEP Communications also joined with Touch America, Inc. to form American Fiber Touch, LLC, an entity that will construct, own, and market a long haul fiber optic route that interconnects the AEP Communications and C3 through Illinois and Missouri.

AEP Communications and C3 also operate business units engaged in marketing energy information. AEP Communications offers a portfolio of energy information data and analysis tools designed to help customers identify energy and cost saving opportunities. C3's energy information services include:

- Meter reading, validation and settlement services.
- Automated meter reading equipment sales and leasing.
- Energy information services.
- Equipment sales and services.

Since the merger of AEP and CSW, a realignment of the energy information business units has taken place through the formation of Datapult Limited Partnership. Energy information services will be offered under the Datapult brand. Evaluation of partnerships and acquisitions will also be a key element of growth for Datapult Limited Partnership in 2001.

SEC Limitations

AEP has received approval from the SEC under PUHCA to issue and sell securities in an amount up to 100% of its average quarterly consolidated retained earnings balance (such average balance was approximately $3.4 billion for the twelve months ended December 31, 2000) for investment in exempt wholesale generators and foreign utility companies. Resources expects to continue its pursuit of new and existing energy generation and delivery projects worldwide.

SEC Rule 58 permits AEP and other registered holding companies to invest up to 15% of consolidated capitalization in energy-related companies. AEPES, an energy-related company under Rule 58, is authorized to engage in energy-related activities, including marketing electricity, gas and other energy commodities.

Risk

These continuing efforts to invest in and develop new business opportunities offer the potential of earning returns which may exceed those of traditional AEP rate-regulated operations. However, they also involve a higher degree of risk which must be carefully considered and assessed. AEP may make additional substantial investments in these and other new businesses.

Reference is made to Market Risks under Item 7A herein for a discussion of certain market risks inherent in AEP business activities.

CONSTRUCTION PROGRAM

New Generation

The AEP System is continuously involved in assessing 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 and the move to increasing competition in the marketplace. See Competition and Business Change.

Committed or anticipated capability changes to the AEP System's generation resources include:

- Purchase from an independent power producer's hydro project with an expected capacity value of 28 megawatts, commencing June 1, 2001.
- Expiration of the Rockport Unit 2 sale of 250 megawatts to Carolina Power & Light Company, an unaffiliated company, on December 31, 2009.

Apart from these changes and temporary power purchases that can be arranged, there are no specific commitments for additions of new generation resources on the AEP System. Given the restructuring taking place in the industry, the extent of the need of AEP's operating companies for any additional generation resources in the foreseeable future is highly uncertain.

Proposed Transmission Facilities

On September 30, 1997, APCo refiled applications in Virginia and West Virginia for certificates to build the Wyoming-Cloverdale

765,000-volt Project. The preferred route for this line is approximately 132 miles in length, connecting APCo's Wyoming Station in southern West Virginia to APCo's Cloverdale Station near Roanoke, Virginia. APCo's estimated cost for the Wyoming-Cloverdale Project is $283,254,000, assuming a 2004 in-service date.

APCo announced this project in 1990. Since then it has been in the process of trying to obtain federal permits and state certificates. At the federal level, the U.S. Forest Service (Forest Service) is directing the preparation of an Environmental Impact Statement (EIS), which is required prior to granting permits for crossing lands under federal jurisdiction. Permits are needed from the (i) Forest Service to cross federal forests, (ii) Army Corps of Engineers to cross the New River and a watershed near the Wyoming Station, and (iii) National Park Service or Forest Service to cross the Appalachian National Scenic Trail.

In June 1996, the Forest Service released a Draft EIS and preliminarily identified a "No Action Alternative" as its preferred alternative. If this alternative were incorporated into the Final EIS, APCo would not be authorized to cross federal forests administered by the Forest Service. The Forest Service stated that it would not prepare the Final EIS until after Virginia and West Virginia determined need and routing issues.

West Virginia: On May 27, 1998, the West Virginia PSC issued an order granting APCo's application for a certificate with respect to the Wyoming-Cloverdale 765,000-volt Project. On October 27, 2000, APCo filed with the West Virginia PSC a request to amend the certificate by adding the alternative end point of Jacksons Ferry in Virginia as discussed below under Virginia.

Virginia: Following several procedural delays and Hearing Examiner's rulings, APCo filed a study in May 1999 identifying the Wyoming-Jacksons Ferry

Project as an alternative project to the Wyoming-Cloverdale Project. The Jacksons Ferry Project proposes a line from Wyoming Station in West Virginia to APCo's existing 765,000-volt Jacksons Ferry Station in Virginia. APCo estimates that the Wyoming-Jacksons Ferry line would be between 82-100 miles in length, including 32 miles in West Virginia previously certified. In May 2000, the Virginia SCC held an evidentiary hearing to consider both projects. On October 2, 2000, the Hearing Examiner's report to the Virginia SCC recommended approval of the Wyoming-Jacksons Ferry Alternative Project. The matter is pending before the Virginia SCC. APCo's estimated cost for the Wyoming-Jacksons Ferry Project is $232,455,000, assuming a 2004 in-service date.

Proposed Completion Schedule: If the Virginia SCC and West Virginia PSC issue the required certificates, APCo will cooperate with the Forest Service to complete the EIS process and obtain the federal permits. The Forest Service has begun preliminary work on a supplement to the Draft EIS. APCo has also begun required consultation with the U.S. Fish and Wildlife Service under the Endangered Species Act.

Management estimates that neither project can be completed before the winter of 2004/2005. However, given the findings in the Draft EIS, APCo cannot presently predict the schedule for completion of the federal permitting process.

Construction Expenditures

The following table shows construction expenditures during 1998, 1999 and 2000 and current estimates of 2001 construction expenditures, in each case including AFUDC but excluding assets acquired under leases.

<TABLE>
<CAPTION>

	1998 ACTUAL	1999 ACTUAL	2000 ACTUAL	2001 ESTIMATE
		(IN THOUSANDS)		
<S>	<C>	<C>	<C>	<C>
AEP System (a)....	$792,100	$866,900	$1,773,400	$2,077,400
AEGCo..........	6,600	8,300	5,200	3,200
APCo...........	204,900	211,400	199,300	394,800
CPL............	126,600	255,800	199,500	295,000
CSPCo..........	115,300	115,300	128,000	146,300
I&M............	148,900	165,300	171,100	127,900
KEPCo..........	43,800	44,300	36,200	53,400
OPCo...........	185,200	193,900	254,000	447,700
PSO............	70,100	104,500	176,900	136,600
SWEPCo.........	84,500	112,900	120,200	123,700
WTU............	37,600	52,600	64,500	77,500

</TABLE>

(a) Includes expenditures of other subsidiaries not shown..

Reference is made to the footnote to the 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 three years.

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.

From time to time, as the System companies have encountered the industry problems described above, such companies also have encountered limitations on their ability to secure the capital necessary to finance construction expenditures.

Environmental Expenditures: Expenditures related to compliance with air and water quality standards, included in the gross additions to plant of the System, during 1998, 1999 and 2000 and the current estimate for 2001 are shown below. Substantial expenditures in addition to the amounts set forth below may be required 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.

<TABLE>
<CAPTION>

	1998 ACTUAL	1999 ACTUAL	2000 ACTUAL	2001 ESTIMATE
	(IN THOUSANDS)			
<S>	<C>	<C>	<C>	<C>
AEGCo................	$800	$8	$70	$100
APCo.................	25,000	24,500	2,100	203,100
CPL..................	(a)	(a)	(a)	3,300
CSPCo................	5,300	10,600	6,600	17,700
I&M..................	13,000	4,500	1,900	7,600
KEPCo................	4,600	1,900	400	23,300
OPCo.................	27,100	37,400	91,200	271,900
PSO..................	(a)	(a)	(a)	1,000
SWEPCo...............	(a)	(a)	(a)	13,200
WTU..................	(a)	(a)	(a)	1,100
AEP System (a).....	$75,800	$78,908	$102,270	$542,300

</TABLE>

(a) Amounts not available for west zone companies of AEP prior to AEP-CSW merger.

FINANCING

It has been the practice of AEP's operating subsidiaries to finance current construction expenditures in excess of available internally generated funds by initially issuing unsecured short-term debt, principally commercial paper and bank loans, at times up to levels authorized by regulatory agencies, and then to reduce the short-term debt with the proceeds of subsequent sales by such subsidiaries of long-term debt securities and cash capital contributions by AEP. If one or more of the subsidiaries are unable to continue the issuance and sale of securities on an orderly basis, such company or companies will be required to consider the curtailment of construction and other outlays or the use of alternative financing arrangements, if available, which may be more costly.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as unsecured debt and leasing arrangements, including the leasing of utility assets and coal mining and transportation equipment and facilities. Pollution control revenue bonds have been used in the past and may be used in the future in connection with the construction of pollution control facilities; however, Federal tax law has limited the utilization of this type of financing except for purposes of certain financing of solid waste disposal facilities and of certain refunding of outstanding pollution control revenue bonds issued before August 16, 1986.

New projects undertaken by AEP's other unregulated subsidiaries are generally financed through equity funds provided by AEP, non-recourse debt incurred on a project-specific basis, debt issued by such subsidiaries or through a combination thereof. See New Business Development and Item 7 for additional information concerning AEP's other unregulated subsidiaries.

RATES AND REGULATION

General

The rates charged by the electric utility subsidiaries of AEP are approved by the FERC or one of the state utility commissions as applicable. The FERC regulates wholesale rates and the state commissions regulate retail rates. In recent years the number of rate increase applications filed by the operating subsidiaries of AEP with their respective state commissions and the FERC has decreased. Under current rate regulation, if increases in operating, construction and capital costs exceed increases in revenues resulting from previously

granted rate increases and increased customer demand, then it may be appropriate for certain of AEP's electric utility subsidiaries to file rate increase applications in the future.

Generally the rates of AEP's operating subsidiaries are determined based upon the cost of providing service including a reasonable return on investment. Certain states served by the AEP System allow alternative forms of rate regulation in addition to the traditional cost-of-service approach. However, the rates of AEP's operating subsidiaries in those states continue to be cost-based. The IURC may approve alternative regulatory plans which could include setting customer rates based on market or average prices, price caps, index-based prices and prices based on performance and efficiency. The Virginia SCC may approve (i) special rates, contracts or incentives to individual customers or classes of customers and (ii) alternative forms of regulation including, but not limited to, the use of price regulation, ranges of authorized returns, categories of services and price indexing.

All of the eleven states served by the AEP System, as well as the FERC, either currently permit the incorporation of fuel adjustment clauses in a utility company's rates and tariffs, which are designed to permit upward or downward adjustments in revenues to reflect increases or decreases in fuel costs above or below the designated base cost of fuel set forth in the particular rate or tariff, or currently permit the inclusion of specified levels of fuel costs as part of such rate or tariff.

AEP cannot predict the timing or probability of approvals regarding applications for additional rate changes, the outcome of action by regulatory commissions or courts with respect to such matters, or the effect thereof on the earnings and business of the AEP System. In addition, current rate regulation may, and in the case of Ohio, Texas and Virginia will, be subject to significant revision. See Competition and Business Change.

FUEL SUPPLY

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

<TABLE>
<CAPTION>

<S>	1996	1997	1998	1999	2000
	<C>	<C>	<C>	<C>	<C>
Coal......................	73%	76%	79%	79%	78%
Gas.......................	12%	12%	14%	15%	13%
Nuclear...................	11%	8%	3%	3%	5%
Hydroelectric and other.....	4%	4%	4%	3%	4%

</TABLE>

Variations in the generation of nuclear power are primarily related to refueling outages and, in 1997 through 1999, the shutdown of the Cook Plant to respond to issues raised by the NRC.

Natural Gas

AEP consumed over 273 billion cubic feet of natural gas during 2000 for the system operating companies, which ranks them as the fourth largest consumer of natural gas in the United States. A majority of the gas fired electric generation plants are connected to at least two natural gas pipelines, which provides greater access to competitive supplies and improves reliability. Natural gas requirements for each plant are supplied by a portfolio of long-term and short-term purchase and transportation agreements which are acquired on a competitive basis and based on market prices.

Coal and Lignite

The Clean Air Act Amendments of 1990 provide for the issuance of annual allowance allocations covering sulfur dioxide emissions at levels below historic emission levels for many coal-fired generating units of the AEP System. Phase I of this program began in 1995 and Phase II began in 2000, with both phases requiring significant changes in coal supplies and suppliers. The full extent of such changes, particularly in regard to Phase II, however, has not been determined. See Environmental and Other Matters -- Air Pollution Control -- Title IV Acid Rain Program for the current compliance plan.

In order to meet emission standards for existing and new emission sources, the AEP System companies will, in any event, have to obtain coal supplies, in addition to coal reserves now owned by System companies, through the acquisition of additional coal reserves and/or by entering into additional supply agreements, either on a long-term or spot basis, at prices and upon terms which cannot now be predicted.

No representation is made that any of the coal rights owned or controlled by the System will, in

future years, produce for the System any major portion of the overall coal supply needed for consumption at the coal-fired generating units of the System. Although AEP believes that in the long run it will be able to secure coal of adequate quality and in adequate quantities to enable existing and new units to comply with emission standards applicable to such sources, no assurance can be given that coal of such quality and quantity will in fact be available. No assurance can be given either that statutes or regulations limiting emissions from existing and new sources will not be further revised in future years to specify lower sulfur contents than now in effect or other restrictions. See Environmental and Other Matters herein.

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 rate-making principles by which such electric utilities would be compensated. In addition, the Federal Government is authorized, under prescribed conditions, to allocate coal and to require the transportation thereof, for the use of power plants or major fuel-burning installations.

System companies have developed programs to conserve coal supplies at System plants which involve, on a progressive basis, limitations on sales of power and energy to neighboring utilities, appeals to customers for voluntary limitations of electric usage to essential needs, curtailment of sales to certain industrial customers, voltage reductions and, finally, mandatory reductions in cases where current coal supplies fall below minimum levels. Such programs have been filed and reviewed with officials of Federal and state agencies and, in some cases, the state regulatory agency has prescribed actions to be taken under specified circumstances by System companies, subject to the jurisdiction of such agencies.

The mining of coal reserves is subject to Federal requirements with respect to the development and operation of coal mines, and to state and Federal regulations relating to land reclamation and environmental protection, including Federal strip mining legislation enacted in August 1977. Continual evaluation and study is given to possible closure of existing coal mines and divestiture or acquisition of coal properties in light of Federal and state environmental and mining laws and regulations which may affect the System's need for or ability to mine such coal.

Western coal purchased by System companies is transported by rail to an affiliated terminal on the Ohio River for transloading to barges for delivery to generating stations on the river. Subsidiaries of AEP own 3,030 coal hopper cars and lease an additional 4,079 coal hopper cars to be used in unit train movements. Subsidiaries of AEP lease 15 towboats, 492 jumbo barges and 145 standard barges. Subsidiaries of AEP also own or lease coal transfer facilities at various other locations.

The System generating companies procure coal from coal reserves which are owned or mined by subsidiaries of AEP, and through purchases pursuant to long-term contracts, or on a spot purchase basis, from unaffiliated producers. The following table shows the amount of coal delivered to the AEP System during the past five years, the proportion of such coal which was obtained either from coal-mining subsidiaries, from unaffiliated suppliers under long-term contracts or through spot or short-term purchases, and the average delivered price of spot coal purchased by System companies:

<TABLE>
<CAPTION>

<S>	1996(a) <C>	1997(a) <C>
Total coal delivered to AEP operated plants (thousands of tons)..........	51,030	54,292
Sources (percentage):		
Subsidiaries....................................	13%	14%
Long-term contracts.............................	71%	66%
Spot or short-term purchases....................	16%	20%
Average price per ton of spot-purchased coal..........	$23.85	$24.38

</TABLE>

(a) Includes east zone companies only.

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The average cost of coal consumed during the past five years by all AEP System companies is shown below. AEP System companies data for 1996 and 1997 includes only AEGCo, APCo, CSPCo, I&M, KEPCo and OPCo.

<TABLE>
<CAPTION>

	1996	1997	1998
		DOLLARS PER TO	
<S>	<C>	<C>	<C>
AEP System Companies	$29.38	$29.68	$29.87
AEGCo	18.22	19.30	19.37
APCo	37.60	36.09	34.81
CPL	28.81	26.93	26.93
CSPCo	31.70	31.69	31.63
I&M	22.99	23.68	22.61
KEPCo	27.25	26.76	27.42
OPCo	35.96	36.00	38.94
PSO	21.84	21.11	20.37
SWEPCo	23.81	23.16	23.02
WTU	24.41	18.19	21.37

</TABLE>

<TABLE>
<CAPTION>

	1996	1997	1998
		CENTS PER MILLION	
<S>	<C>	<C>	<C>
AEP System Companies	139.44	140.13	142.17
AEGCo	109.25	115.21	112.63
APCo	152.54	146.54	141.76
CPL	143.12	136.40	137.00
CSPCo	134.60	134.44	134.15
I&M	121.16	123.36	118.02
KEPCo	114.42	110.37	112.15
OPCo	151.55	151.66	164.44
PSO	125.87	120.91	116.73
SWEPCo	155.88	152.79	150.62
WTU	146.26	109.13	126.22

</TABLE>

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 unrest and weather conditions which may interrupt deliveries. At December 31, 2000, the System's coal inventory was approximately 35 days of normal System usage. This estimate assumes that the total supply would be utilized by increasing or decreasing generation at particular plants.

The following tabulation shows the total consumption during 2000 of the coal-fired generating units of AEP's principal electric utility subsidiaries, coal requirements of these units over the remainder of their useful lives and the average sulfur content of coal delivered in 2000 to these units. Reference is made to Environmental and Other Matters for information concerning current emissions limitations in the AEP System's various jurisdictions and the effects of the Clean Air Act Amendments.

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<TABLE>
<CAPTION>

<S>	TOTAL CONSUMPTION DURING 2000 (IN THOUSANDS OF TONS) <C>	ESTIMATED REQUIREMENTS FOR REMAINDER OF USEFUL LIVES (IN MILLIONS OF TONS) <C>
AEGCo (a)	4,944	211
APCo	11,662	384
CPL	2,745	41
CSPCo	6,368	222(b)
I&M (c)	7,342	241
KEPCo	2,794	82
OPCo	20,723	533(d)
PSO	4,199	47
SWEPCo	12,720	151
WTU	1,519	35

(a) Reflects AEGCo's 50% interest in the Rockport Plant.
(b) Includes coal requirements for CSPCo's interest in Beckjord, Stuart and Zimmer Plants.
(c) Includes I&M's 50% interest in the Rockport Plant.
(d) Total does not include OPCo's portion of Sporn Plant.

</TABLE>

AEGCo: See Fuel Supply -- I&M for a discussion of the coal supply for the Rockport Plant.

APCo: Substantially all of the coal consumed at APCo's generating plants is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis.

The average sulfur content by weight of the coal received by APCo at its generating stations approximated 0.8% during 2000, whereas the maximum sulfur content permitted, for emission standard purposes, for existing plants in the regions in which APCo's generating stations are located ranged between 0.78% and 2% by weight depending in some circumstances on the calorific value of the coal which can be obtained for some generating stations.

CPL: CPL has coal supply agreements with four coal suppliers which delivered approximately 2,255,000 tons of coal during the year 2000. One contract for Colorado coal extends through 2001 and has 1,000,000 tons to be delivered during that year. Approximately one half of the coal delivered to Coleto Creek is from Wyoming with the other half from Colorado. Both sources supply low sulfur coal with a limit of 1.2 lbs/MMBtu.

CSPCo: CSPCo has coal supply agreements with unaffiliated suppliers for the delivery of approximately 3,120,000 tons per year through 2004. Some of this coal is washed to improve its quality and consistency for use principally at Unit 4 of the Conesville Plant.

CSPCo has been informed by CG&E and DP&L that, with respect to the CCD Group units partly owned but not operated by CSPCo, sufficient coal has been contracted for or is believed to be available for the approximate lives of the respective units operated by them. Under the terms of the operating agreements with respect to CCD Group units, each operating company is contractually responsible for obtaining the needed fuel.

I&M: I&M has two coal supply agreements with unaffiliated Wyoming suppliers for low sulfur coal from surface mines principally for consumption by the Rockport Plant. Under these agreements, the suppliers will sell to I&M, for consumption by I&M at the Rockport Plant or consignment to other System companies, coal with an average sulfur content not exceeding 1.2 pounds of sulfur dioxide per million Btu's of heat input. One contract with remaining deliveries of 45,138,543 tons expires on December 31, 2014 and another contract with remaining deliveries of 26,400,000 tons expires on December 31, 2004.

All of the coal consumed at I&M's Tanners Creek Plant is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis.

KEPCo: Substantially all of the coal consumed at KEPCo's Big Sandy Plant is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis. KEPCo has coal supply agreements with unaffiliated suppliers pursuant to which KEPCo will receive approximately 1,600,000 tons of coal in 2001. To the extent that KEPCo has additional coal requirements, it may purchase coal from the spot market and/or suppliers under contract to supply other System companies.

OPCo: The coal consumed at OPCo's generating plants is obtained from both affiliated and unaffiliated suppliers. The coal obtained from unaffiliated suppliers is purchased under long-term contracts and/or on a spot purchase basis.

OPCo and certain of its coal-mining subsidiaries own or control coal reserves in the State of Ohio containing approximately 145,000,000 tons of clean recoverable coal and ranging in sulfur content between 3.8% and 4.5% sulfur by weight (weighted average, 4.1%), which reserves are presently being mined. OPCo and certain of its mining subsidiaries own an additional 113,000,000 tons of clean recoverable coal in Ohio which ranges in sulfur content between 2.4% and 3.4% sulfur by weight (weighted average 2.7%). Recovery of this coal would require substantial development.

OPCo and certain of its coal-mining subsidiaries also own or control coal reserves in the State of West Virginia which contain approximately 96,000,000 tons of clean recoverable coal ranging in sulfur content between 1.4% and 4.0% sulfur by weight (weighted average, 2.0%) of which approximately 19,000,000 tons can be recovered based upon existing mining plans and projections and employing current mining practices and techniques.

PSO: The coal contract under which coal is supplied to PSO provides the entire plant requirements with at least 20,285,000 tons remaining to be delivered. The coal is supplied from Wyoming and has a maximum sulfur content of 1.2 lbs. SO2 per MMBtu.

SWEPCo: SWEPCo has one coal contract with a Wyoming producer that provides the majority of its coal requirements. The coal is supplied from Wyoming and has a maximum sulfur content of 1.2 lbs. SO2 per MMBtu. SWEPCo has remaining deliveries of approximately 31 million tons through 2006 under this contract. In 2000, the remaining coal requirements for SWEPCo were obtained under short term coal agreements with Wyoming producers. SWEPCo also has a mine-mouth lignite operation in East Texas that provides a low cost source to the Pirkey Plant. North American Coal Company's Sabine Mining Company operates the mine.

WTU: WTU has one coal contract designed to supply approximately two thirds of the coal requirements for the Oklaunion Power Station. This contract has approximately 10,920,000 tons remaining to be delivered between 2001 and the middle of 2006. The remaining one third of the coal requirements delivered in 2000 for Oklaunion were under two contracts with Wyoming suppliers. Both were low sulfur coal contracts.

Nuclear

I&M and STPNOC have made commitments to meet certain of the nuclear fuel requirements of the Cook Plant and STP, respectively. The nuclear fuel cycle consists of:

- Mining and milling of uranium ore to uranium concentrates.
- Conversion of uranium concentrates to uranium hexafluoride.
- Enrichment of uranium hexafluoride.
- Fabrication of fuel assemblies.
- Utilization of nuclear fuel in the reactor.
- Disposition of spent fuel.

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.

CPL and the other STP participants have entered into contracts with suppliers for 100% of the uranium concentrate sufficient for the operation of both STP units through Fall 2005 and with an additional 50% of the uranium concentrate needed for STP through Spring 2006. In addition, CPL and the other STP participants have entered into contracts with suppliers for 100% of the nuclear fuel conversion service sufficient for the operation of both STP units through Spring 2003, with additional flexible contracts to provide at least 50% of the conversion service needed for STP through 2005. CPL and the other STP participants have entered into flexible contracts to provide for 100% of enrichment through Spring 2003, with additional flexible contracts to provide at least 40% of enrichment services through Fall 2005. Also, fuel fabrication services have been contracted for operation through 2028 for Unit 1 and 2029 for Unit 2.

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.

The costs of nuclear fuel consumed by I&M and CPL do not assume any residual or salvage value for residual plutonium and uranium.

Nuclear Waste and Decommissioning

Reference is made to Management's Discussion and Analysis of Results of Operations and Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters in the financial statements and Commitments and Contingencies in the footnotes to these statements that are incorporated by reference in Items 7 and 8, respectively, for information with respect to nuclear waste and decommissioning and related litigation.

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 these studies.
- Availability of nuclear waste disposal facilities.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant and STP will not be significantly greater than current projections.

Low-Level Waste: The Low-Level Waste Policy Act of 1980 (LLWPA) mandates that the responsibility for the disposal of low-level 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. To facilitate this approach, the LLWPA authorized states to enter into regional compacts for low-level waste disposal subject to Congressional approval. The LLWPA also specified that, beginning in 1986, approved compacts may prohibit the importation of low-level waste from other regions, thereby providing a strong incentive for states to enter into compacts. Michigan, the state where the Cook Plant is located, was a member of the Midwest Compact, but its membership was revoked in 1991. As a result, Michigan is responsible for developing a disposal site for the low-level waste generated in Michigan.

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Although Michigan amended its law regarding low-level waste site development in 1994 to allow a volunteer to host a facility, little progress has been made to date. A bill was introduced in 1996 to further address the issue but no action was taken. Development of required legislation and progress with the site selection process has been inhibited by many factors, and management is unable to predict when a new disposal site for Michigan low-level waste will be available.

Texas is a member of the Texas Compact, which includes the states of Maine and Vermont. Texas had identified a disposal site in Hudspeth County for construction of a low-level waste disposal facility. During the licensing process for the Hudspeth site, that site was found to be unsuitable. No additional site has been considered. Several bills have been submitted in the Texas legislature in 2001 to address this issue. Management is unable to predict when a disposal site for Texas low-level waste will be available.

On July 1, 1995, the disposal site in South Carolina reopened to accept waste from most areas of the U.S., including Michigan and Texas. This was the first opportunity for the Cook Plant to dispose of low-level waste since 1990. To the extent practicable, the waste formerly placed in storage and the waste presently generated by the Cook Plant and STP are now being sent to the disposal site.

Under state law, the amounts of low-level radioactive waste being disposed of at the South Carolina facility from non-regional generators, such as the Cook Plant and STP, are limited and being reduced. Non-regional access to the South Carolina facility is currently allowed through the end of fiscal year 2008.

ENVIRONMENTAL AND OTHER MATTERS

AEP's subsidiaries are 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. 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.

It is expected that:

- Costs related to environmental requirements will eventually be reflected in the rates of AEP's electric utility subsidiaries, or where states are deregulating generation, unbundled transition period generation rates, stranded cost wires charges and future market prices for electricity.

- AEP's electric utility subsidiaries will be able to provide for required environmental controls.

However, some customers may curtail or cease operations as a consequence of higher energy costs. There can be no assurance that all such costs will be recovered. Moreover, legislation recently adopted by certain states and proposed at the state and federal level governing restructuring of the electric utility industry may also affect the recovery of certain costs. See Competition and Business Change.

Except as noted herein, AEP's subsidiaries that own or operate generating, transmission and distribution facilities are in substantial compliance with pollution control laws and regulations.

Reference is made to Management's Discussion and Analysis of Results of Operations and Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters and the footnote to the financial statements entitled Commitments and Contingencies incorporated by reference in Items 7 and 8, respectively, for further information with respect to environmental matters.

Air Pollution Control

For the AEP System operating companies, compliance with the CAA is requiring substantial expenditures that generally are being recovered through the rates of AEP's operating subsidiaries. Certain matters discussed below may require significant additional operating and capital expenditures. However, there can be no assurance that all such costs will be recovered. See Construction Program -- Construction Expenditures.

Title I National Ambient Air Quality Standards Attainment: In July 1997, Federal EPA revised the ozone and particulate matter National Ambient Air Quality Standards (NAAQS), creating a new eight-hour ozone standard and establishing a new standard for particulate matter less than 2.5 microns in diameter (PM2.5). Both of these new standards have the potential to affect adversely the operation of AEP System generating units. In May 1999, the U.S. Court of Appeals for the District of Columbia Circuit remanded the ozone and PM2.5 NAAQS to Federal EPA. In February 2001, the U.S. Supreme Court issued an opinion reversing in part and affirming in part the Court of Appeals decision. The Supreme Court remanded the case to the Court of Appeals for further proceedings, including a review of whether adoption of the standards was arbitrary and capricious and directed Federal EPA to develop a policy for implementing the revised ozone standard in conformity with the CAA.

NOx SIP Call: In October 1998, Federal EPA issued a final rule (NOx transport SIP call or NOx SIP Call) establishing state-by-state NOx emission budgets for the five-month ozone season to be met beginning May 1, 2003. The NOx budgets originally applied to 22 eastern states and the District of Columbia and are premised mainly on the assumption of controlling power plant NOx emissions projected for the year 2007 to 0.15 lb. per million Btu (approximately 85% below 1990 levels), although the reductions could be substantially greater for certain State Implementation Plans. The SIP call was accompanied by a proposed Federal Implementation Plan, which could be implemented in any state that fails to submit an approvable SIP. The NOx reductions called for by Federal EPA are targeted at coal-fired electric utilities and may adversely impact the ability of electric utilities to obtain new and modified source permits or to operate affected facilities without making significant capital expenditures.

In October 1998, the AEP System operating companies joined with certain other parties seeking a review of the final NOx SIP Call rule in the U.S. Court of Appeals for the District of Columbia Circuit. In March 2000, the court issued a decision upholding the major provisions of the rule. The court subsequently extended the date for submission of SIP revisions until October 30, 2000, and the compliance deadline until May 31, 2004. On March 5, 2001, the U.S. Supreme Court denied petitions filed by industry petitioners, including AEP System operating companies, seeking review of the Court of Appeals decision. In December 2000, Federal EPA issued a determination that eleven states, including certain states in which AEP System operating companies have sources covered by the NOx SIP Call rule, had failed to submit complying SIP revisions. This determination has been appealed by AEP System operating companies and unaffiliated utilities to the U.S. Court of Appeals for the District of Columbia Circuit.

In April 2000, the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NOx emissions from utility sources, including those of CPL and SWEPCo. The rule compliance date is May 2003 for CPL and May 2005 for SWEPCo.

Preliminary estimates indicate that compliance with the revised NOx SIP Call rule, and SIP revisions already adopted, could result in required capital expenditures for the AEP System of approximately $1.6 billion. AEP operating company estimates are as follows:

<TABLE>
<CAPTION>

<S>	(IN MILLIONS) <C>
AEGCo	$125
APCo	365
CPL	57
CSPCo	106
I&M	202
KEPCo	140
OPCo	606
SWEPCo	28

</TABLE>

In June 2000 OPCo announced that it was beginning a $175 million installation of selective catalytic reduction technology (expected to be operational in 2001) to reduce NOx emissions on its two-unit 2,600 MW Gavin Plant. Construction of selective catalytic reduction technology on Amos Plant Unit 3, which is jointly owned by OPCo and APCo, and APCo's Mountaineer Plant is scheduled to begin in 2001. The Amos and Mountaineer projects (expected to be completed in 2002) are estimated to cost a total of $230 million. Management has undertaken the Gavin, Amos and Mountaineer projects to meet applicable NOx emission reduction requirements.

Since compliance costs cannot be estimated with certainty, the actual costs to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers through regulated rates and/or future market prices for electricity where generation is deregulated, they will have a material adverse effect on future results of operations, cash flows and possibly financial condition of AEP and its affected subsidiaries.

Section 126 Petitions: In January 2000, Federal EPA adopted a revised rule granting petitions filed by certain northeastern states under Section 126 of the CAA. The petitions sought significant reductions in nitrogen oxide emissions from utility and industrial sources. The rule imposes emission reduction requirements comparable to the NOx SIP Call rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Certain AEP System operating companies and other utilities filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit. Briefing has been completed and oral argument was held in December 2000. Cost estimates for compliance with Section 126 are projected to be somewhat less than those set forth above for the NOx SIP Call rule reflecting the fact that Section 126 does not apply to I&M's Rockport Plant.

West Virginia SO2 Limits: West Virginia promulgated SO2 limitations, which Federal EPA approved in February 1978. The emission limitations for OPCo's Mitchell Plant have been approved by Federal EPA for primary ambient air quality (health-related) standards only. West Virginia is obligated to reanalyze SO2 emission limits for the Mitchell Plant with respect to secondary ambient air quality (welfare-related) standards. Because the CAA provides no specific deadline for approval of emission limits to achieve secondary ambient air quality standards, it is not certain when Federal EPA will take dispositive action regarding the Mitchell Plant.

In August 1994, Federal EPA issued a Notice of Violation to OPCo alleging that Kammer Plant was operating in violation of the applicable federally enforceable SO2 emission limit. In May 1996, the Notice of Violation and an enforcement action subsequently filed by Federal EPA were resolved through the entry of a consent decree in the U.S. District Court for the Northern District of West Virginia. Kammer Plant has achieved and maintained compliance with the applicable SO2 emission limit for a period in excess of one year, pursuant to the provisions of the consent decree. OPCo is currently seeking the termination of the consent decree.

Short Term SO2 Limits: In January 1997, Federal EPA proposed a new intervention level program under the authority of Section 303 of the CAA to address five-minute peak SO2 concentrations believed to pose a health risk to certain segments of the population. The proposal establishes a "concern" level and an "endangerment" level. States must investigate exceedances of the concern level and decide whether to take corrective action. If the endangerment level is exceeded, the state must take action to reduce SO2 levels. In January 2001, Federal EPA published a Federal Register notice inviting comment with respect to its decision not to promulgate a five-minute SO2 NAAQS and intent to take final action on the intervention level program by the summer of 2001. The effect of this proposed intervention program on AEP operations cannot be predicted at this time.

Hazardous Air Pollutants: Hazardous air pollutant (HAP) emissions from utility boilers are potentially subject to control requirements under Title III of the CAAA which specifically directed Federal EPA to study potential public health impacts of HAPs emitted from electric utility steam generating units. In December 2000, Federal EPA announced its intent to regulate emissions of mercury from coal and oil-fired power plants, concluding that these emissions pose significant hazards to public health. A decision on whether to regulate other HAPs emissions from these sources was deferred.

Federal EPA added coal and oil-fired electric utility steam generating units to the list of "major sources" of HAPs under Section 112 (c) of the CAA, which compels the development of "Maximum Achievable Control Technology" (MACT) standards for these units. Listing under Section 112 (c) also compels a preconstruction permitting obligation to establish case-by-case MACT standards for each new, modified, or

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reconstructed source in the category. MACT standards for utility mercury emissions are scheduled to be proposed by December 2003 and finalized by December 2004. On February 16 and 20, 2001, utility industry groups filed petitions for review of Federal EPA's action in the U.S. Court of Appeals for the District of Columbia Circuit. On February 23, 2001, the Utility Air Regulatory Group (which includes AEP System operating companies as members) filed a petition with Federal EPA seeking reconsideration of the decision to regulate mercury emissions from power plants under Section 112(c) of the CAA.

In addition, Federal EPA is required to study the deposition of hazardous pollutants in the Great Lakes, the Chesapeake Bay, Lake Champlain, and other coastal waters. As part of this assessment, Federal EPA is authorized to adopt regulations to prevent serious adverse effects to public health and serious or widespread environmental effects. In 1998, Federal EPA determined that the CAA is adequate to address any adverse public health or environmental effects associated with the atmospheric deposition of hazardous air pollutants in the Great Lakes.

Title IV Acid Rain Program: The Acid Rain Program (Title IV) of the CAAA created an emission allowance program pursuant to which utilities are authorized to emit a designated quantity of SO2, measured in tons per year.

Phase II of the Acid Rain Program, which affects all fossil fuel-fired steam generating units with capacity greater than 25 megawatts imposed more stringent SO2 emission control requirements beginning January 1, 2000. If a unit emitted SO2 in 1985 at a rate in excess of 1.2 pounds per million Btu heat input, the Phase II allowance allocation is premised upon an emission rate of 1.2 pounds at 1985 utilization levels. Future SO2 allowance requirements will be met through accumulation, acquisition, the use of controls or fuels, or a combination thereof.

Title IV of the CAAA also regulates emissions of NOx. Federal EPA has promulgated NOx emission limitations for all boiler types in the AEP System at levels significantly below original design, which were to be achieved by January 1, 2000 on a unit-by-unit or System-wide average basis. AEP sources subject to Title IV of the CAAA are in compliance with the provisions thereof.

Regional Haze: In July 1999, Federal EPA finalized rules to regulate regional haze attributable to anthropogenic emissions. The primary goal of the new regional haze program is to address visibility impairment in and around "Class I" protected areas, such as national parks and wilderness areas. Because regional haze precursor emissions are believed by Federal EPA to travel long distances, Federal EPA proposes to regulate such precursor emissions in every state. Under the proposal, each state must develop a regional haze control program that imposes controls necessary to steadily reduce visibility impairment in Class I areas on the worst days and that ensures that visibility remains good on the best days.

The AEP System is a significant emitter of fine particulate matter and other precursors of regional haze. Federal EPA's regional haze rule may have an adverse financial impact on AEP as it may trigger the requirement to install costly new pollution control devices to control emissions of fine particulate matter and its precursors (including SO2 and NOx). The actual impact of the regional haze regulations cannot be determined at this time. AEP System operating companies and other utilities filed a petition seeking a review of the regional haze rule in the U.S. Court of Appeals for the District of Columbia Circuit in August 1999.

In January 2001, Federal EPA announced that it is considering the issuance of proposed guidelines for states to use in setting Best Available Retrofit Technology (BART) emission limits for power plants and other large emission sources. The proposal would call for technologies to reduce visibility-impairing emissions by 90 to 95 percent. Emission trading programs could be used in lieu of unit-by-unit BART requirements under the proposal, provided they yield greater visibility improvement and emission reductions.

Permitting and Enforcement: The CAAA expanded the enforcement authority of the federal government by:

- .Increasing the range of civil and criminal penalties for violations of the CAA and enhancing administrative civil provisions.

- Imposing a national operating permit system, emission fee program and enhanced monitoring, recordkeeping and reporting requirements.

Section 103 of CERCLA and Section 304 of the Emergency Planning and Community Right-to-Know Act require notification to state and federal authorities of releases of reportable quantities (RQs) of hazardous and extremely hazardous substances. A number of these substances are emitted by AEP's power plants and other sources. Until recently, emissions of these substances, whether expressly limited in a permit or otherwise subject to federal review or waiver (e.g., mercury), were deemed "federally permitted releases" which did not require emergency notification. In December 1999, Federal EPA published interim guidance in the Federal Register, which provided that any hazardous substance or extremely hazardous substance not expressly and individually limited in a permit must be reported if they are emitted at levels above an RQ. Specifically, constituents of regulated pollutants (e.g., metals contained in particulate matter) were not deemed to be federally permitted. AEP System operating companies provided supplemental information regarding air releases from their facilities in the spring of 2000. Annual follow-up reports will be submitted in April 2001.

Global Climate Change: In December 1997, delegates from 167 nations, including the U.S., agreed to a treaty, known as the "Kyoto Protocol," establishing legally-binding emission reductions for gases suspected of causing climate change. If the U.S. becomes a party to the treaty, it will be bound to reduce emissions of CO2, methane and nitrous oxides by 7% below 1990 levels and emissions of hydrofluorcarbons, perfluorocarbons and sulfur hexafluoride 7% below 1995 levels in the years 2008-2012. The Protocol requires ratification by at least 55 nations that account for at least 55% of developed countries' 1990 emissions of CO2 to enter into force.

Although the U.S. agreed to the treaty and President Clinton signed it on November 12, 1998, the treaty has not been sent to the Senate for its advice and consent to ratification. In a letter dated March 13, 2001 from President Bush to four U. S. senators, he indicated his opposition to the Kyoto Protocol and said he does not believe that the government should impose mandatory emissions reductions for CO2 on the electric utility sector.

The treaty is currently incomplete and international negotiations that were to resolve the outstanding issues were suspended in November 2000. The major issues requiring resolution include:

- Participation by developing countries in the control requirements.
- Rules, procedures, methodologies and guidelines of the treaty's emission trading and joint implementation provisions.
- Crediting for terrestrial carbon sequestration activities.
- Compliance enforcement provisions.

Negotiations are scheduled to resume in July 2001.

Since the AEP System is a significant emitter of carbon dioxide, its results of operations, cash flows and financial condition could be materially adversely affected by the imposition of limitations on CO2 emissions if compliance costs cannot be fully recovered from customers. In addition, any such severe program to reduce CO2 emissions could impose substantial costs on industry and society and erode the economic base that AEP's operations serve. However, it is management's belief that the Kyoto Protocol is highly unlikely to be ratified or implemented in the U. S. in its current form.

New Source Review: In July 1992, Federal EPA published final regulations governing application of new source rules to generating plant repairs and pollution control projects undertaken to comply with the CAA. Generally, the rule provides that plants undertaking pollution control projects will not trigger New Source Review (NSR) requirements. The Natural Resources Defense Council and a group of utilities, including five AEP System operating companies, filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking a review of the regulations. In July 1998, Federal EPA requested comment on proposed revisions to

the New Source Review rules, which would change New Source Review applicability criteria by eliminating exclusions contained in the current regulation.

New Source Review Litigation: On November 3, 1999, following issuance by Federal EPA of substantial information requests to AEP System operating companies, the Department of Justice (DOJ), on Federal EPA's behalf, filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges AEP made modifications to generating units at certain of its coal-fired generating plants over the course of the past 25 years that extend unit operating lives or restore or increase unit generating capacity without a preconstruction permit in violation of the CAA. The complaint named OPCo's Cardinal Unit 1, Mitchell, Muskingum River, and Sporn plants and I&M's Tanners Creek plant. Federal EPA also issued Notices of Violation to AEP alleging similar violations at certain other AEP plants.

In March 2000, DOJ filed an amended complaint that added allegations for certain of the AEP plants previously named in the complaint as well as counts for APCo's Amos, Clinch River, and Kanawha River plants, CSPCo's Conesville Plant, and OPCo's Kammer Plant. In addition to the allegations regarding New Source Review and New Source Performance Standard violations, DOJ included allegations regarding visible particulate emission violations for Cardinal and Muskingum River plants.

A number of northeastern and eastern states have been allowed to intervene in the litigation, and a number of special interest groups filed a separate complaint based on substantially similar allegations, which has been consolidated with the DOJ complaint. In addition to the plants named by the government and special interest groups, the intervenor states have included allegations concerning OPCo's Gavin Plant.

On May 10, 2000, AEP filed a motion to dismiss with the District Court, which, if granted, would dispose of most of the claims of the government and intervenors. This motion is currently pending before the Court.

On February 23, 2001, the plaintiffs filed a motion for partial summary judgment seeking a determination that four projects undertaken on units at Sporn, Cardinal, and Clinch River Plants do not constitute "routine maintenance, repair and replacement" as used in the NSR programs. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense.

A number of unaffiliated utilities have also received notices of violation, complaints, or administrative orders relating to NSR. A notice of violation was issued in June 2000 to DP&L with respect to its ownership interest in Stuart Station, in which CSPCo also owns a 26 percent interest. W.C. Beckjord Unit 6, operated by CG&E, in which CSPCo owns a 12.5 percent interest, is also the subject of an enforcement action. CG&E and VEPCo have each entered into an agreement in principle with the DOJ in an attempt to resolve the litigation, but no final agreements have been announced. One of the unaffiliated utilities, Tampa Electric Company, has reached a settlement in its litigation with the Federal government.

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). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts Federal EPA's contentions, could be substantial.

In November 2000, several environmental groups filed a petition with Ohio EPA seeking to have the draft Title V operating permits for OPCo's Cardinal and Muskingum River plants as well as the Beckjord Plant and a plant owned by an unaffiliated utility, modified to incorporate requirements and timetables for compliance with New Source Review requirements. In December 2000, a petition was filed by these groups with the Administrator of Federal EPA seeking a similar modification of the final Title V permit for CSPCo's Conesville Plant. Ohio EPA has refused to consider these petitions outside the regular Title V permit processing procedures or to interfere with the resolution of these issues by the District Court.

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In the event AEP does not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed could materially adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates, and where states are deregulating generation, unbundled transition period generation rates, wires charges and future market prices for energy.

Water Pollution Control

The Clean Water Act prohibits the discharge of pollutants to waters of the United States from point sources except pursuant to an NPDES permit issued by Federal EPA or a state under a federally authorized state program.

Under the Clean Water Act, effluent limitations requiring application of the best available technology economically achievable are to be applied, and those limitations require that no pollutants be discharged if Federal EPA finds elimination of such discharges is technologically and economically achievable.

The Clean Water Act provides citizens with a cause of action to enforce compliance with its pollution control requirements. Since 1982, many such actions against NPDES permit holders have been filed. To date, no AEP System plants have been named in such actions.

All AEP System generating plants are required to have NPDES permits and have received them. Under Federal EPA's regulations, operation under an expired NPDES permit is authorized provided an application is filed at least 180 days prior to expiration. Renewal applications are being prepared or have been filed for renewal of NPDES permits that expire in 2001.

The NPDES permits generally require that certain thermal impact study programs be undertaken. These studies have been completed for all System plants. Thermal variances are in effect for all plants with once-through cooling water. The thermal variances for CSPCo's Conesville and OPCo's Muskingum River plants impose thermal management conditions that could result in load curtailment under certain conditions, but the cost impacts are not expected to be significant. Based on favorable results of in-stream biological studies, the thermal limits for both Conesville and Muskingum River plants were raised in the renewed permits issued in 1996. Consequently, the potential for load curtailment and adverse cost impacts was further reduced.

Section 316(b) of the Clean Water Act requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. Under a revised court established schedule, Federal EPA is required to develop regulations defining adverse impacts and BTA for new sources by November 2001. Regulations applicable to existing power plants are not required to be issued by Federal EPA until August 2003. As part of the rulemaking, Federal EPA has issued questionnaires to power plants, including AEP System plants, requesting information on impingement and entrainment of aquatic organisms from existing plant cooling water intakes. Federal EPA's rulemaking could result in a definition of BTA that would affect any new plant construction and could ultimately require retrofitting of certain existing plant intake structures. Such changes would involve costs for AEP System operating companies, but the significance of these costs cannot be determined at this time.

Certain mining operations conducted by System companies as discussed under Fuel Supply are also subject to federal and state water pollution control requirements, which may entail substantial expenditures for control facilities, not included at present in the System's construction cost estimates set forth herein.

Section 303 of the Federal Clean Water Act requires states to adopt stringent water quality standards for a large category of toxic pollutants and to identify specialized control measures for dischargers to waters where it is shown that water quality standards are not being met. In order to bring these waters back into compliance, total maximum daily load (TMDL) allocations of these pollutants will be made, and subsequently translated into discharge limits in NPDES permits. Federal EPA has also directed that states take action to adopt enhanced anti-degradation of water quality requirements. Implementation of these provisions

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could result in significant costs to the AEP System if biological monitoring requirements and water quality-based effluent limits and requirements are placed in NPDES permits.

In March 1995, Federal EPA finalized a set of rules that establish minimum water quality standards, anti-degradation policies and implementation procedures for more stringently controlling releases of toxic pollutants into the Great Lakes system. This regulatory package is called the Great Lakes Water Quality Initiative (GLWQI). The most direct compliance cost impact could be related to I&M's Cook Plant. Based on Federal EPA's current policy on intake credits and site specific variables and Michigan's implementation strategy, management does not presently expect the GLWQI will have a significant adverse impact on Cook Plant operations. If Indiana and Ohio eventually adopt the GLWQI criteria for statewide application, AEP System plants located in those states could be adversely affected, although the significance depends on the implementation strategy of those states.

Oil Pollution Act: The Oil Pollution Act of 1990 (OPA) defines certain facilities that, due to oil storage volume, and location, could reasonably be expected to cause significant and substantial harm to the environment by discharging oil. Such facilities must operate under approved spill response plans and implement spill response training and drill programs. OPA imposes substantial penalties for failure to comply. AEP System operating companies with oil handling and storage facilities meeting the OPA criteria have in place required response plans, training and drill programs.

Solid and Hazardous Waste

Section 311 of the Clean Water Act imposes substantial penalties for spills of Federal EPA-listed hazardous substances into water and for failure to report such spills. CERCLA expanded the reporting requirement to cover the release of hazardous substances generally into the environment, including water, land and air. AEP's subsidiaries store and use some of these hazardous substances, including PCBs contained in certain capacitors and transformers, but the occurrence and ramifications of a spill or release of such substances cannot be predicted.

CERCLA, RCRA and similar state laws provide governmental agencies with the authority to require cleanup of hazardous waste sites and releases of hazardous substances into the environment and to seek compensation for damages to natural resources. Since liability under CERCLA is strict, joint and several, and can be applied retroactively, AEP System operating companies which previously disposed of PCB-containing electrical equipment and other hazardous substances may be required to participate in remedial activities at such disposal sites should environmental problems result.

AEP System operating companies are identified as Potentially Responsible Parties (PRPs) for five federal sites where remediation has not been completed, including APCo at one site, CSPCo at one site, I&M at two sites, and OPCo at one site. Management's present estimates do not anticipate material clean-up costs for identified sites for which AEP subsidiaries have been declared PRPs. However, if significant costs are incurred for cleanup, future results of operations and possibly financial condition could be adversely affected unless the costs can be recovered through rates and/or future market prices for electricity where generation is deregulated.

Regulations issued by Federal EPA under the Toxic Substances Control Act govern the use, distribution and disposal of PCBs, including PCBs in electrical equipment. Deadlines for removing certain PCB-containing electrical equipment from service have been met.

In addition to handling hazardous substances, the System companies generate solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash and flue gas desulfurization wastes. These wastes presently are considered to be non-hazardous under RCRA and applicable state law and the wastes are treated and disposed of in surface impoundments or landfills in accordance with state permits or authorization or are beneficially utilized. As required by RCRA, Federal EPA evaluated whether high volume coal combustion wastes (such as fly ash, bottom ash and flue gas desulfurization wastes) should be regulated as hazardous waste. In August 1993, Federal EPA issued a regulatory determination that such high

volume coal combustion wastes should not be regulated as hazardous waste. Federal EPA chose to address separately the issue of low volume wastes (such as metal and boiler cleaning wastes) associated with burning coal and other fossil fuels. In May 2000, Federal EPA issued a regulatory determination that such low volume wastes are also excluded from regulation under the RCRA hazardous waste provisions when mixed and co-managed with high volume fossil fuel combustion wastes.

All presently generated hazardous waste is being disposed of at permitted off-site facilities in compliance with applicable federal and state laws and regulations. For System facilities that generate such wastes, System companies have filed the requisite notices and are complying with RCRA and applicable state regulations for generators. Nuclear waste produced at the Cook Plant and STP and regulated under the Atomic Energy Act is excluded from regulation under RCRA.

Underground Storage Tanks: Federal EPA's technical requirements for underground storage tanks containing petroleum required retrofitting or replacement of an appreciable number of tanks. Compliance costs for tank replacement were not significant. Some limited site remediation associated with tank removal is ongoing, but these costs are not expected to be significant.

Electric and Magnetic Fields (EMF)

EMF is 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 is 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, the majority of studies have indicated no such association.

The Energy Policy Act of 1992 established a coordinated Federal EMF research program which ended in 1998. In 1999, the National Institute of Environmental Health Sciences (NIEHS), as required by the Act, provided a report to Congress summarizing the results of this program. The report concluded that "the probability that ...EMF is truly a health hazard is currently small" and that the evidence that exists for health effects is "insufficient to warrant aggressive regulatory actions." Nevertheless, the NIEHS identified several areas where further research might be warranted. AEP has supported EMF research through the years and continues to fund the Electric Power Research Institute's EMF research program, contributing over $400,000 to this program in 2000 and intending to contribute a similar amount in 2001. See Research and Development.

AEP's participation in these programs is a continuation of its efforts to monitor and support further research and to communicate with its customers and employees about this issue. Residential customers of AEP are provided information and field measurements on request, although there is no scientific basis for interpreting such measurements.

A number of lawsuits based on EMF-related grounds have been filed against electric utilities. A suit was filed on May 23, 1990 against I&M involving claims that EMF from a 345 KV transmission line caused adverse health effects. On March 23, 1998 the court ruled that the plaintiffs failed to prove that I&M caused any of the injuries claimed by the plaintiffs. This part of the trial court's decision was upheld on appeal. Certain issues unrelated to health effects are pending at the trial court. No specific amount has been requested for damages in this case. Mediation is scheduled for June, 2001.

Some states have enacted regulations to limit the strength of magnetic fields at the edge of transmission line rights-of-way. No state which the AEP System serves has done so.

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 ratepayers.

RESEARCH AND DEVELOPMENT

AEP and its subsidiaries are involved in over 150 research projects that are directed to:

- Exploring new methods of generating electricity, such as through renewable sources (e.g., wind, solar).
- Developing more efficient methods of operating generating plants.
- Reducing emissions resulting from the burning of fossil fuels (coal and natural gas).
- Improving the efficiency, utilization and reliability of the transmission and distribution systems.
- Exploring the application of new electrotechnologies.
- Exploring the use and application of distributed generation.

AEP System operating companies are members of the Electric Power Research Institute (EPRI), an organization founded in 1973 that manages research and development initiatives on behalf of its members. EPRI's members include investor owned and public utilities, independent power producers, international organizations and others.

AEP participates in EPRI programs that meet its research and development objectives. Total AEP dues to EPRI were $17,000,000 for 2000, $22,000,000 for 1999 and $23,000,000 for 1998. Of these amounts, the former CSW System paid approximately $7,000,000 in 2000, $8,000,00 in 1999 and $8,000,000 in 1998 for EPRI programs.

Total research and development expenditures by AEP and its subsidiaries, including EPRI dues, were approximately $20,000,000 for the year ended December 31, 2000, $25,000,000 for the year ended December 31, 1999 and $32,000,000 for the year ended December 31, 1998.

Item 2. PROPERTIES

At December 31, 2000, the subsidiaries of AEP owned (or leased where indicated) generating plants with the net power capabilities (winter rating) shown in the following table:

<TABLE>
<CAPTION>

COMPANY	STATIONS	COAL MW	NATURAL GAS MW	HYDRO MW	NUCLEAR MW
<S>	<C>	<C>	<C>	<C>	<C>
AEGCo	1(a)	1,300			
APCo	17(b)	5,081		777	
CPL	12(c)(d)	686	3,175	6	630
CSPCo	6(e)	2,595			
I&M	10(a)	2,295		11	2,110
KEPCo	1	1,060			
OPCo	8(b)(f)	8,464		48	
PSO	8(c)	1,018	2,873		
SWEPCo	9	1,848	1,797		
WTU	12(c)	377	999		
Totals:	79	24,724	8,862	842	2,740

</TABLE>

(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) CPL, PSO, and WTU jointly own the Oklaunion power station. Their respective ownership interests are reflected in this table.

(d) Reflects CPL'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 OPCo's General James M. Gavin Plant are leased. The lease terminates in 2010 unless extended.

(g) PSO and WTU have 25 MW and 10 MW respectively of facilities designed primarily to burn oil. WTU has one 6 MW wind farm facility.

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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, 2000 is listed below.

<TABLE>
<CAPTION>

FACILITY	COMPANY	LOCATION	CAPACITY TOTAL MW
<S>	<C>	<C>	<C>
Brush II	CSWEnergy	Colorado	68
Fort Lupton	CSWEnergy	Colorado	272
Mulberry	CSWEnergy	Florida	120
Orange Cogen	CSWEnergy	Florida	103
Newgulf	CSWEnergy	Texas	85
Sweeny (a)	CSWEnergy	Texas	360
Total U.S.			1,008

Medway	CSWInternational	UnitedKingdom	675
Altamira	CSWInternational	Mexico	118
Total International			793

</TABLE>

(a) During 2001, additional development at the Sweeny facility is expected to add approximately 120 MW to current capacity.

See Item 1 under Fuel Supply, for information concerning coal reserves owned or controlled by subsidiaries of AEP.

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 765,000-volt lines:

<TABLE>
<CAPTION>

<S>	TOTAL OVERHEAD CIRCUIT MILES OF TRANSMISSION AND DISTRIBUTION LINES <C>	CIRCUIT MILES OF 765,000-VOLT LINES <C>
AEP System (a)	208,809(b)	2,023
APCo	50,187	642
CPL	31,125	---
CSPCo (a)	13,864	---
I&M	20,602	614
KEPCo	10,385	258
OPCo	29,620	509
PSO	18,565	---
SWEPCo	18,851	---
WTU	12,439	---

</TABLE>

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

TITLES

The AEP System's electric generating stations 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 the System in the realty on which its facilities are located are considered by it to be adequate for its use in the conduct of its 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. System companies generally have the right of eminent domain whereby they may, if necessary, acquire, perfect or secure titles to or easements on privately-held lands used or to be used in their utility operations.

Substantially all the physical properties of the AEP System operating companies 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

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

PEAK DEMAND

The east zone system is interconnected through 121 high-voltage transmission interconnections with 25 neighboring electric utility systems. The all-time and 2000 one-hour peak system demands were 25,940,000 and 23,223,000 kilowatts, respectively (which included 7,314,000 and 5,341,000 kilowatts, respectively, of scheduled deliveries to unaffiliated systems which the system might, on appropriate notice, have elected not to schedule for delivery) and occurred on June 17, 1994 and August 7, 2000, respectively. The net dependable capacity to serve the system load on such date, including power available under contractual obligations, was 23,457,000 and 23,790,000 kilowatts, respectively. The all-time and 2000 one-hour internal peak demands were 19,952,000 and 19,167,000 kilowatts, respectively, and occurred on July 30, 1999 and January 28, 2000, respectively. The net dependable capacity to serve the system load on such date, including power dedicated under contractual arrangements, was 23,829,000 and 24,036,000 kilowatts, respectively. The all-time one-hour integrated and internal net system peak demands and 2000 peak demands for the east zone generating subsidiaries are shown in the following tabulation:

<TABLE>
<CAPTION>

	ALL-TIME ONE-HOUR INTEGRATED NET SYSTEM PEAK DEMAND		2000 ONE-HOUR INTEGRATED NET SYSTEM PEAK DEMAND	
	(IN THOUSANDS)			
	NUMBER OF KILOWATTS	DATE	NUMBER OF KILOWATTS	DATE
<S>	<C>	<C>	<C>	<C>
APCo........	8,303	January 17, 1997	7,509	December 20, 2000
CSPCo.......	4,239	August 2, 2000	4,240	August 2, 2000
I&M.........	5,040	August 15, 2000	5,048	August 15, 2000
KEPCo.......	1,860	January 10, 2001	1,761	December 20, 2000
OPCo........	7,291	June 17, 1994	6,199	August 2, 2000

</TABLE>

<TABLE>
<CAPTION>

	ALL-TIME ONE-HOUR INTEGRATED NET INTERNAL PEAK DEMAND		2000 ONE-HOUR INTEGRATED NET INTERNAL PEAK DEMAND	
	(IN THOUSANDS)			
	NUMBER OF KILOWATTS	DATE	NUMBER OF KILOWATTS	DATE
<S>	<C>	<C>	<C>	<C>
APCo.........	6,908	February 5, 1996	6,558	January 28, 2000
CSPCo........	3,804	July 30, 1999	3,499	August 31, 2000
I&M..........	4,127	July 30, 1999	3,949	August 30, 2000
KEPCo.......	1,579	January 3, 2001	1,558	January 27, 2000
OPCo.........	5,705	June 11, 1999	5,029	June 14, 2000

</TABLE>

The all-time and 2000 one-hour internal peak demand for the west zone system was 14,234,000 kilowatts on August 31, 2000. The all-time one-hour internal net system peak demands and 2000 peak demands for the west zone generating subsidiaries are shown in the following tabulation:

<TABLE>
<CAPTION>

	ALL-TIME ONE-HOUR INTEGRATED NET INTERNAL PEAK DEMAND		2000 ONE-HOUR INTEGRATED NET INTERNAL PEAK DEMAND	
	(IN THOUSANDS)			
	NUMBER OF KILOWATTS	DATE	NUMBER OF KILOWATTS	DATE
<S>	<C>	<C>	<C>	<C>
CPL	4,623	September 5, 2000	4,623	September 5, 2000
PSO..........	3,823	August 30, 2000	3,823	August 30, 2000
SWEPCo.......	4,625	August 31, 2000	4,625	August 31, 2000
WTU.........	1,537	September 5, 2000	1,537	September 5, 2000

</TABLE>

HYDROELECTRIC PLANTS

AEP has 18 facilities, of which 16 are licensed through FERC. The new license for the Elkhart hydroelectric plant in Indiana was issued January 11, 2001 and extends for a period of thirty years. The license for the Mottville hydroelectric plant in Michigan expires in 2003. A notice of intent to relicense was filed in 1998. The application for new license will be filed in 2001.

COOK NUCLEAR PLANT AND STP

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

<TABLE>
<CAPTION>

	COOK PLANT		STP(a)	
	UNIT 1	UNIT 2	UNIT 1	UNIT 2
<S>	<C>	<C>	<C>	<C>
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	1,020,000	1,090,000	1,250,600	1,250,600
NET CAPACITY FACTORS				
2000 (c)	1.4%	50.0%	78.2%	96.1%
1999 (c)	0%	0%	88.0%	89.4%

</TABLE>

(a) Reflects total plant.
(b) For economic or other reasons, operation of the Cook Plant and STP for the full term of their operating licenses cannot be assured.
(c) The Cook Plant was shut down in September 1997 to respond to issues raised regarding the operability of certain safety systems. The restart of both units of the Cook Plant was completed with Unit 2 reaching 100% power on

July 5, 2000 and Unit 1 achieving 100% power on January 3, 2001.

Costs associated with the operation (excluding fuel), maintenance and retirement of nuclear plants continue to be of greater significance 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 construction and operation of nuclear facilities. I&M and CPL 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 CPL 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 Competition and Business Change.

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. Future losses or liabilities which are not completely insured, unless allowed to be recovered through rates, could have a material adverse effect on results of operations and the financial condition of AEP, CPL, I&M and other AEP System companies.

Reference is made to the footnote to the financial statements entitled Commitments and Contingencies that is incorporated by reference in Item 8 for information with respect to nuclear incident liability insurance.

Item 3. LEGAL PROCEEDINGS

Federal EPA Notice of Violation to OPCo: On August 31, 2000, Region V, Federal EPA, issued a Notice of Violation (NOV) to OPCo's Gavin Plant in connection with stack emissions. Among other alleged violations, the NOV alleges violation of the Federal EPA-approved Ohio air pollution nuisance rule. AEP has submitted a request for a conference to discuss the NOV with Region V representatives.

Municipal Franchise Fee Litigation: CPL has been involved in litigation regarding municipal franchise fees in Texas as a result of a class action suit filed by the City of San Juan, Texas in 1996. The City of San Juan claims CPL underpaid municipal franchise fees and seeks damages of up to $300 million plus attorney's fees. CPL filed a counterclaim for overpayment of franchise fees.

During 1997, 1998 and 1999 the litigation moved procedurally through the Texas Court System and was sent to mediation without resolution.

In 1999 a class notice was mailed to each of the cities served by CPL. Over 90 of the 128 cities declined to participate in the lawsuit. However, CPL has pledged that if any final, non-appealable court decision awards a judgment against CPL for a franchise underpayment, CPL will extend the principles of that decision, with regard to any franchise underpayment, to the cities that declined to participate in the litigation. In December 1999, the court ruled that the class of plaintiffs would consist of approximately 30 cities. A trial date for June 2001 has been set.

Although management believes that it has substantial defenses to the cities' claims and intends to defend itself against the cities' claims and pursue its counterclaim vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

COLI Litigation: On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against AEP in its suit against the United States over deductibility of interest claimed by AEP in its consolidated federal income tax return related to its COLI program. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 AEP paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets pending

the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced in 2000 as follows:

<TABLE>
<CAPTION>

<S>	(IN MILLIONS) <C>
AEP System operating companies........................	$319
APCo..	82
CSPCo...	41
I&M...	66
KEPCo...	8
OPCo..	118

</TABLE>

The Company plans to appeal the decision.

See Item 1 for a discussion of certain environmental matters.

Reference is made to the footnote to the financial statements entitled Commitments and Contingencies incorporated by reference in Item 8 for further information with respect to other legal proceedings.

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

AEP, APCO, CPL, I&M, OPCO AND SWEPCO. None.

AEGCO, CSPCO, KEPCO, PSO AND WTU. 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, 2001.

<TABLE>
<CAPTION>

NAME ---- <S>	AGE --- <C>	OFFICE (a) ---------- <C>
E. Linn Draper, Jr...................	59	Chairman of the Board, President and Chie Service Corporation

Thomas V. Shockley, III..............	55	Vice Chairman of the Service Corporation
Paul D. Addis........................	47	Executive Vice President-Wholesale/Energy
Donald M. Clements, Jr...............	51	Executive Vice President-Corporate Develo Corporation
Henry W. Fayne.......................	54	Executive Vice President-Finance and Anal
William J. Lhota.....................	61	Executive Vice President- Energy Delivery
Susan Tomasky........................	47	Executive Vice President-Legal, Policy an Corporation
J. H. Vipperman......................	60	Executive Vice President-Shared Services

</TABLE>

(a) All of the executive officers listed above have been employed by the Service Corporation or System companies in various capacities (AEP, as such, has no employees) during the past five years, except for Messrs. Addis and Shockley and Ms. Tomasky. Prior to joining the Service Corporation in February 1997 in his present position, Mr. Addis was Executive Vice President (1992-1993) and President (1993-January 1997) of Louis Dreyfus Electric Power, Inc. and President of Duke/Louis Dreyfus LLC (1995-January 1997). Mr. Addis became an executive officer of AEP effective January 1, 2000. Prior to joining the Service Corporation in July 1998 as Senior Vice President, Ms. Tomasky was a partner with the law firm of Hogan & Hartson (August 1997-July 1998) and General Counsel of the Federal Energy Regulatory Commission (May 1993-August 1997). Ms. Tomasky became an executive officer of AEP effective with her promotion to Executive Vice President on January 26, 2000. Prior to joining the Service Corporation in his current position upon the merger with CSW, Mr. Shockley was President and Chief Operating Officer of CSW (1997-2000) and Senior Vice President of CSW (1980-1997). 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 the Service Corporation, or both, as the case may be.

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APCO, CPL, I&M, OPCO AND SWEPCO. The names of the executive officers of APCo, CPL, I&M, OPCo and SWEPCo, the positions they hold with these companies, their ages as of March 1, 2001, and a brief account of their business experience during the past five years appear below. The directors and executive officers of APCo, CPL, I&M, OPCo and SWEPCo are elected annually to serve a one-year term.

<TABLE>
<CAPTION>

NAME	AGE	POSITION (a)(b)
<S>	<C>	
E. Linn Draper, Jr........	59	Director of CPL and SWEPCo Chairman of the Board and Chief Executive Officer of Director of APCo, I&M and OPCo Chairman of the Board and Chief Executive Officer of Chairman of the Board, President and Chief Executive Officer of AEP and the Service Corporation
Thomas V. Shockley, III...	55	Director and Vice President of APCo, CPL, I&M, OPCo a Vice Chairman of AEP and the Service Corporation President and Chief Operating Officer of CSW Executive Vice President of CSW
Henry W. Fayne............	54	Director of CPL and SWEPCO Director of APCo

		Director of OPCo Director of I&M Vice President of CPL and SWEPCo Vice President of APCo, I&M and OPCo Vice President and Chief Financial Officer of AEP Executive Vice President-Finance and Analysis of the Executive Vice President-Financial Services of the Service Corporation Senior Vice President-Corporate Planning & Budgeting of the Service Corporation
William J. Lhota..........	61	Director of CPL and SWEPCo Director of APCo Director of I&M and OPCo President and Chief Operating Officer of CPL and SWEP President and Chief Operating Officer of APCo, I&M an Executive Vice President-Energy Delivery of the Servi Executive Vice President of the Service Corporation
Susan Tomasky............	47	Director and Vice President of APCo, CPL, I&M, OPCo a Executive Vice President-Legal, Policy and Corporate General Counsel of the Service Corporation Senior Vice President and General Counsel of the Serv Hogan & Hartson (law firm) General Counsel of the FERC

</TABLE>

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<TABLE>
<CAPTION>

NAME	AGE	POSITION (a)(b)
<S>	<C>	
J. H. Vipperman..........	60	Director of CPL and SWEPCo Director of APCo Director of I&M and OPCo Vice President of CPL and SWEPCo Vice President of APCo, I&M and OPCo Executive Vice President-Shared Services of the Servi Executive Vice President-Corporate Services of the Se Executive Vice President-Energy Delivery of the Servi

</TABLE>

(a) Dr. Draper is a director of BCP Management, Inc., which is the general partner of Borden Chemicals and Plastics L.P., and Mr. Lhota is a director of Huntington Bancshares Incorporated and State Auto Financial Corporation.

(b) Dr. Draper, Messrs. Fayne, Lhota, Shockley and Vipperman and Ms. Tomasky are directors of AEGCo, CSPCo, KEPCo, PSO and WTU. Dr. Draper and Mr. Shockley are also directors of AEP.

PART II

Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

AEP. AEP Common Stock is traded principally on the New York Stock Exchange. The following table sets forth for the calendar periods indicated the high and low sales prices for the Common Stock as reported on the New York Stock Exchange Composite Tape and the amount of cash dividends paid per share of Common Stock.

<TABLE>
<CAPTION>

QUARTER ENDED	PER SHARE MARKET PRICE HIGH	LOW
<S>	<C>	<C>
March 1999	48-3/16	39-5/16
June 1999	44-1/16	37-7/16
September 1999	37-7/8	33-1/2
December 1999	35-13/16	30-9/16
March 2000	34-15/16	25-15/16
June 2000	38-1/2	29-7/16
September 2000	40	29-15/16
December 2000	48-15/16	36-3/16

</TABLE>

At December 31, 2000, AEP had approximately 160,000 shareholders of record.

AEGCO, APCO, CPL, CSPCO, I&M, KEPCO, OPCO, PSO, SWEPCO AND WTU. 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 2000 and 1999 are incorporated by reference to the material under Statement of Retained Earnings in the 2000 Annual Reports.

Item 6. SELECTED FINANCIAL DATA

AEGCo, CSPCo, KEPCo, PSO AND WTU. Omitted pursuant to Instruction I(2)(a).

AEP, APCo, CPL, I&M, OPCo AND SWEPCo. The information required by this item is incorporated herein by reference to the material under Selected Consolidated Financial Data in the 2000 Annual Reports.

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

AEGCo, CSPCo, KEPCo, PSO AND WTU. 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 Narrative Analysis of Results of Operations in the 2000 Annual Reports.

AEP, APCo, CPL, I&M, OPCo AND SWEPCo. The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Results of Operations and Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters in the 2000 Annual Reports.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEGCo, AEP, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo AND WTU. The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters in the 2000 Annual Reports.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEGCo, AEP, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo AND WTU. The information required by this item is incorporated herein by reference to the financial statements and supplementary data described under Item 14 herein.

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

AEGCo, AEP, APCo, CSPCo, I&M, KEPCo AND OPCo. None.

CPL, PSO, SWEPCo AND WTU. The information required by this item is incorporated herein by reference to each company's Current Report on Form 8-K dated July 5, 2000.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANTS

AEGCo, CSPCo, KEPCo, PSO AND WTU. 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 of the definitive proxy statement of AEP for the 2001 annual meeting of shareholders, to be filed within 120 days after December 31, 2000. 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 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000. Reference also is made to the information under the caption Executive Officers of the Registrants in Part I of this report.

CPL AND SWEPCo. The information required by this item is incorporated herein by reference to the material under Election of Directors of the definitive information statement of APCo for the 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000. Reference also is made to the information under the caption Executive Officers of the Registrants in Part I of this report.

I&M. The names of the directors and executive officers of I&M, the positions they hold with I&M, their ages as of March 12, 2001, and a brief account of their business experience during the past five years appear below and under the caption Executive Officers of the Registrants in Part I of this report.

<TABLE>
<CAPTION>

NAME	AGE	POSITION (a)
<S>	<C>	<C>
K. G. Boyd.............	49	Director Vice President - Fort Wayne Distribution Operations Indiana Region Manager Fort Wayne District Manager
Marc E. Lewis..........	46	Director Assistant General Counsel of the Service Corporation Senior Counsel of the Service Corporation

		Senior Attorney of the Service Corporation
Susanne M. Moorman.....	51	Director General Manager, Community Services Manager, Customer Services Operations Director, Customer Services
John R. Sampson.........	48	Director and Vice President Indiana & Michigan State President Site Vice President, Cook Nuclear Plant Plant Manager, Cook Nuclear Plant
Jackie S. Siefker.......	47	Director Manager, Distribution Systems District Manager
D. B. Synowiec..........	57	Director Plant Manager, Rockport Plant
W. E. Walters...........	53	Director Michiana Region Manager Director of Projects

</TABLE>

(a) Positions are with I&M unless otherwise indicated.

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Item 11. EXECUTIVE COMPENSATION

AEGCo, CSPCo, KEPCo, PSO AND WTU. 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 2001 annual meeting of shareholders to be filed within 120 days after December 31, 2000.

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 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000.

CPL, I&M AND SWEPCo. 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 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000.

The following table sets forth the aggregate cash and other compensation for services rendered for the fiscal years of 2000, 1999 and 1998 paid or awarded to the presidents of CPL and SWEPCo.

Summary Compensation Table

<TABLE>
<CAPTION>

ANNUAL COMPENSATION

NAME AND PRINCIPAL POSITION	YEAR	SALARY ($)	BONUS ($)	OTH ANN COMPEN
<S>	<C>	<C>	<C>	
J. GONZALO SANDOVAL - General manager/president of CPL (3)	2000	143,323	38,153	
	1999	138,863	31,268	
	1998	138,115	34,955	
MICHAEL H. MADISON - President of SWEPCo (3)	2000	179,922	78,937	
	1999	186,944	91,065	5
	1998	178,953	87,380	28

<CAPTION>

NAME AND PRINCIPAL POSITION	LONG-TERM COMPENSATION AWARDS SECURITIES UNDERLYING OPTIONS (#)	LONG-TERM COMPENSATION PAYOUTS LTIP PAYOUTS ($)(1)	ALL OTHER COMPENSATION ($)(2)
<S>	<C>	<C>	<C>
J. GONZALO SANDOVAL - General manager/president of CPL (3)	6,250	14,656	7,068
	0	19,661	7,200
	0	9,961	6,580
MICHAEL H. MADISON - President of SWEPCo (3)	15,000	192,444	198,211
	0	19,661	8,103
	0	9,961	7,900

</TABLE>

----

(1) The awards reflected in this column are the value of restricted shares paid out under CSW's Long-Term Incentive Plan and, in the case of Mr. Madison, performance share units. Upon vesting, shares of AEP Common Stock were reissued without restrictions. The amounts reported in the Summary Compensation Table represent the market value of the shares at the date of grant.

(2) Detail of the 2000 amounts in the All Other Compensation column is shown below.

<TABLE>
<CAPTION>

Item	Mr. Sandoval	Mr.
<S>	<C>	
Savings Plan Matching Contributions..................	$7,068	
Personal Liability Insurance.........................	0	
Change-in Control Payment............................	0	
Vehicle Allowance....................................	0	
Total All Other Compensation......................	$7,068	$

</TABLE>

(3) Messrs. Sandoval and Madison resigned their positions on June 28, 2000, but remained employees of the AEP System.

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Option Grants in 2000

<TABLE>
<CAPTION>

	INDIVIDUAL GRANTS		
NAME	NUMBER OF SECURITIES UNDERLYING OPTIONS GRANTED (#) (1)	PERCENT OF TOTAL OPTIONS GRANTED TO EMPLOYEES IN 2000 (2)	EXERCISE OR BASE PRICE ($/SH)
<S>	<C>	<C>	<C>
J. Gonzalo Sandoval	6,250	0.1%	35.625
Michael H. Madison	15,000	0.2%	35.625

</TABLE>

---

(1) Options were granted on September 20, 2000, pursuant to the AEP 2000 Long-Term Incentive Plan. All options granted on this date have an exercise price equal to the closing price of AEP Common Stock on the New York Stock Exchange Composite Transactions Tape on September 20, 2000. These options will vest in equal increments, annually, over a three-year period beginning on January 1, 2002. Options also fully vest upon termination due to retirement after one year from the grant date or due to disability or death and expire five years thereafter, or on their scheduled expiration date if earlier. Options expire upon termination of employment for reasons other than retirement, disability or death, unless the Human Resources Committee determines that circumstances warrant continuation of the options for up to five years. Options are nontransferable.

(2) A total of 6,046,000 options were granted in 2000.

(3) Value was calculated using the Black-Scholes option valuation model. The actual value, if any, ultimately realized depends on the market value of AEP's Common Stock at a future date. Significant assumptions are shown below:

<TABLE>

<S>	<C>	<C>
Stock Price Volatility	24.75%	Dividend Yi
Risk-Free Rate of Return	6.50%	Option Term

</TABLE>

Aggregated Option Exercises in 2000 and Year-End Option Values

<TABLE>
<CAPTION>

NAME	SHARE ACQUIRED ON EXERCISE (#) (1)	VALUE REALIZED ($) (1)	NUMBER OF SECURITIES UNEXERCISED OPTIONS AT	
			EXERCISABLE	U
<S>	<C>	<C>	<C>	<
J. Gonzalo Sandoval	--	--	1,750	
Michael H. Madison	--	--	6,281	

<CAPTION>

VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS AT 12-31-00 ($) (2)

NAME	EXERCISABLE	UNEXERCISABLE
<S>	<C>	<C>
J. Gonzalo Sandoval	0	67,969
Michael H. Madison	52,448	163,125

</TABLE>

---

(1) Neither of these officers exercised options during 2000.
(2) Based on the difference between the closing price of AEP Common Stock on the New York Stock Exchange Composite Transactions Tape on December 29, 2000 ($46.50) and the option exercise price. "In-the-money" means the market price of the stock is greater than the exercise price of the option on the date indicated.

Cash Balance Retirement Plan

CPL and SWEPCo maintain the Cash Balance Plan for eligible employees. In addition, these companies maintain the Special Executive Retirement Plan (SERP), a non-qualified plan that provides benefits that cannot be payable under the Cash Balance Plan because of maximum limitations imposed on such plans by the Internal Revenue Code. Under the cash balance formula, each participant has an account for recordkeeping purposes only, to which dollar amount credits are allocated annually based on a percentage of the participant's pay. Pay for the Cash Balance Plan includes base pay, bonuses, overtime, and commissions. The applicable percentage is determined by the age and years of vesting service the participant has as of December 31 of each year.

The following table shows the percentage used to determine dollar amount credits at the age and years of service indicated:

<TABLE>
<CAPTION>

SUM OF AGE PLUS YEARS OF SERVICE	APPLICABLE PERCENTAGE
<S>	<C>
<30	3.0%
30-39	3.5%
40-49	4.5%
50-59	5.5%
60-69	7.0%
70 or more	8.5%

</TABLE>

As of December 31, 2000, the sum of age plus years of service of Messrs. Sandoval and Madison were 78 and 81, respectively.

At retirement or other termination of employment, an amount equal to the vested balance (including qualified and SERP benefit) then credited to the account is payable to the participant in the form of an immediate or deferred lump sum or annuity. Benefits (both from the Cash Balance Plan and the SERP) under the cash balance formula are not subject to reduction for Social Security benefits or other offset amounts. The estimated annual benefits payable to Messrs. Sandoval and Madison as a single life annuity at age 65 under the Cash Balance Plan and the SERP are $93,508 for Mr. Sandoval and $122,555 for Mr. Madision.

These amounts are based on the following assumptions:

- Salary used is base pay paid for calendar year 2000 assuming no future increases plus bonus at 2000 target level.
- Conversion of the lump-sum cash balance to a single life annuity at age 65, based on an interest rate of 5.78% and the 1983 Group Annuity Mortality Table.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

AEGCo, CSPCo, KEPCo, PSO AND WTU. 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 2001 annual meeting of shareholders to be filed within 120 days after December 31, 2000.

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 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000.

CPL AND SWEPCo. 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 APCo for the 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000.

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, 2001, by each director and nominee of I&M as of March 12, 2001 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 name. Fractions of shares and units have been rounded to the nearest whole number.

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<TABLE>
<CAPTION>

NAME	SHARES(a)
<S>	<C>
Karl G. Boyd	2,137
E. Linn Draper, Jr	9,535(c)
Henry W. Fayne	5,590(d)
Marc E. Lewis	898

William J. Lhota	18,854(c)
Susanne M. Moorman	685
John R. Sampson	430
Thomas V. Shockley, III	93,965(e)
Jackie S. Siefker	3,093
David B. Synowiec	2,505
Susan Tomasky	1,744
Joseph H. Vipperman	12,460(c)
William E. Walters	7,441
All Directors and Executive Officers	244,568(d)

</TABLE>

(a) Includes share equivalents held in the AEP Retirement Savings Plan (and for Mr. Shockley, the CSW Retirement Savings Plan) in the amounts listed below:

<TABLE>
<CAPTION>

NAME	AEP RETIREMENT SAVINGS PLAN (SHARE EQUIVALENTS)
Mr. Boyd	2,137
Dr. Draper	3,947
Mr. Fayne	5,014
Mr. Lewis	898
Mr. Lhota	16,674
Ms. Moorman	685
Mr. Sampson	430

</TABLE>

<TABLE>
<CAPTION>

NAME	AEP RETIREMENT SAVINGS PLAN (SHARE EQUIVALENTS)
Mr. Shockley	6,234
Ms. Siefker	3,093
Mr. Synowiec	2,505
Ms. Tomasky	1,744
Mr. Vipperman	11,626
Mr. Walters	7,441
All Directors and Executive Officers	62,428

</TABLE>

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.

(b) This column includes amounts deferred in stock units and held under AEP's officer benefit plans.

(c) Includes the following numbers of shares held in joint tenancy with a family member: Dr. Draper, 5,588; Mr. Lhota, 2,180; and Mr. Vipperman, 76.

(d) Does not include, for Messrs. Fayne, Lhota and Vipperman, 85,231 shares in the American Electric Power System Educational Trust Fund over which Messrs. Fayne, Lhota and Vipperman share voting and investment power as trustees (they disclaim beneficial ownership). The amount of shares shown for all directors and executive officers as a group includes these shares

(e) Includes the following numbers of shares held by family members over which beneficial ownership is disclaimed: Mr. Shockley, 496.

(f) Includes 49, 938 shares for Mr. Shockley attributable to options exercisable within 60 days.

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

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

AEP, APCo, CPL, I&M, OPCo AND SWEPCo. None.

AEGCo, CSPCo, KEPCo, PSO AND WTU. Omitted pursuant to Instruction I(2)(c).

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PART IV

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

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

1. FINANCIAL STATEMENTS:

The following financial statements have been incorporated herein by reference pursuant to Item 8.

<TABLE>
<CAPTION>

<S>

AEGCo:
Independent Auditors' Report; Statements of Income for the years ended December 31, 2000, 1999 and 1998; Statements of Retained Earnings for the years ended December 31, 2000, 1999 and 1998; Statements of Cash Flows for the years ended December 31, 2000, 1999 and 1998; Balance Sheets as of December 31, 2000 and 1999; Statements of Capitalization as of December 31, 2000 and 1999; Combined Notes to Financial Statements.

AEP and its subsidiaries consolidated:
Consolidated Statements of Income for the years ended December 31, 2000, 1999 and 1998; Consolidated Balance Sheets as of December 31, 2000 and 1999; Consolidated Statements of Cash Flows for the years ended December 31, 2000, 1999 and 1998; Consolidated Statements of Common Shareholders' Equity for the years ended December 31, 2000, 1999 and 1998; Combined Notes to Financial Statements; Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries at December 31, 2000 and 1999; Schedule of Consolidated Long-term Debt of Subsidiaries at December 31, 2000 and 1999; Independent Auditors' Reports.

APCo, CPL, CSPCo, I&M, OPCo, PSO and SWEPCo:
Independent Auditors' Report(s); Consolidated Statements of Income for the years ended December 31, 2000, 1999 and 1998; Consolidated Balance Sheets as of December 31, 2000 and 1999; Consolidated Statements of Cash Flows for the years ended December 31, 2000, 1999 and 1998; Consolidated Statements of Retained Earnings for the years ended December 31, 2000, 1999 and 1998; Consolidated Statements of Capitalization as of December 31, 2000 and 1999; Schedule of Consolidated Long-term Debt as of December 31, 2000 and 1999; Combined Notes to Financial Statements.

KEPCo and WTU:
Independent Auditors' Report(s); Statements of Income for the years ended December 31, 2000, 1999 and 1998; Statements of Retained

Earnings for the years ended December 31, 2000, 1999 and 1998; Statements of Cash Flows for the years ended December 31, 2000, 1999 and 1998; Balance Sheets as of December 31, 2000 and 1999; Statements of Capitalization as of December 31, 2000 and 1999; Schedule of Long-term Debt as of December 31, 2000 and 1999; Combined Notes to Financial Statements.

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).

Independent Auditors' Report

3. EXHIBITS:

Exhibits for AEGCo, AEP, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo and WTU are listed in the Exhibit Index and are incorporated herein by reference
</TABLE>

(b) No Reports on Form 8-K were filed during the quarter ended December 31, 2000.

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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/ H. W. FAYNE

(H. W. FAYNE, VICE PRESIDENT AND CHIEF FINANCIAL OFFICER)

Date: March 20, 2001

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.

<TABLE>
<CAPTION>

	SIGNATURE	TITLE	
<S>		<C>	
(I)	PRINCIPAL EXECUTIVE OFFICER:		
	*E. LINN DRAPER, JR.	Chairman of the Board, President, Chief Executive Officer And Director	
(II)	PRINCIPAL FINANCIAL OFFICER:		
	/S/ H. W. FAYNE	Vice President and Chief Financial Officer	Mar

(H. W. FAYNE)

(III) PRINCIPAL ACCOUNTING OFFICER:

/S/ L. V. ASSANTE Deputy Controller Mar

(L. V. ASSANTE)

(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
*JAMES L. POWELL
*RICHARD L. SANDOR
*THOMAS V. SHOCKLEY, III
*DONALD G. SMITH
*LINDA GILLESPIE STUNTZ
*KATHRYN D. SULLIVAN
*MORRIS TANENBAUM Mar

*By: /S/ H. W. FAYNE

(H. W. FAYNE, ATTORNEY-IN-FACT)
</TABLE>

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
APPALACHIAN POWER COMPANY
CENTRAL POWER AND LIGHT COMPANY
COLUMBUS SOUTHERN POWER COMPANY
KENTUCKY POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY
WEST TEXAS UTILITIES COMPANY

BY: /S/ A. A. PENA

(A. A. PENA, VICE PRESIDENT AND TREASURER)

Date: March 20, 2001

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.
<TABLE>
<CAPTION>

SIGNATURE	TITLE

<S>		<C>	<C>
(i)	PRINCIPAL EXECUTIVE OFFICER:		
	*E. LINN DRAPER, JR.	Chairman of the Board, Chief Executive Officer And Director	
(ii)	PRINCIPAL FINANCIAL OFFICER: /S/ A. A. PENA (A. A. PENA)	Vice President, Treasurer, And Director	Marc
(iii)	PRINCIPAL ACCOUNTING OFFICER:		
	/S/ L. V. ASSANTE (L. V. ASSANTE)	Deputy Controller	Marc
(iv)	A MAJORITY OF THE DIRECTORS:		
	*HENRY W. FAYNE *WM. J. LHOTA *THOMAS V. SHOCKLEY, III *SUSAN TOMASKY *J. H. VIPPERMAN		Marc
*By:	/S/ A. A. PENA (A. A. PENA, ATTORNEY-IN-FACT)		

</TABLE>

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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/ A. A. PENA

(A. A. PENA, VICE PRESIDENT AND TREASURER)

Date: March 20, 2001

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.

<TABLE>
<CAPTION>

	SIGNATURE	TITLE
<S>		<C>

(i)	PRINCIPAL EXECUTIVE OFFICER:	
	*E. LINN DRAPER, JR.	Chairman of the Board, Chief Executive Officer And Director
(ii)	PRINCIPAL FINANCIAL OFFICER:	
	/S/ A. A. PENA (A. A. PENA)	Vice President and Treasurer
(iii)	PRINCIPAL ACCOUNTING OFFICER:	
	/S/ L. V. ASSANTE (L. V. ASSANTE)	Deputy Controller
(iv)	A MAJORITY OF THE DIRECTORS:	
	*K. G. BOYD * HENRY W. FAYNE *MARC E. LEWIS *WM. J. LHOTA *SUSANNE M. MOORMAN *JOHN R. SAMPSON *THOMAS V. SHOCKLEY, III *JACKIE S. SIEFKER *D. B. SYNOWIEC *SUSAN TOMASKY *J. H. VIPPERMAN *W. E. WALTERS	
*By:	/s/ A. A. Pena (A. A. PENA, ATTORNEY-IN-FACT)	

</TABLE>

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INDEX TO FINANCIAL STATEMENT SCHEDULES

<TABLE>
<CAPTION>

<S>
INDEPENDENT AUDITORS' REPORT ....

The following financial statement schedules are included in this report on the pages indicated.

</TABLE>

INDEPENDENT AUDITORS' REPORT

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARIES:

We have audited the consolidated financial statements of American Electric Power Company, Inc. and its subsidiaries and the financial statements of certain of its subsidiaries, listed in Item 14 herein, as of December 31, 2000 and 1999, and for each of the three years in the period ended December 31, 2000, and have issued our reports thereon dated February 26, 2001; such financial statements and reports are included in the 2000 Annual Reports and are incorporated herein by reference. Our audits also included the financial statement schedules of American Electric Power Company, Inc. and its subsidiaries and of certain of its subsidiaries, listed in Item 14, except for the financial statement schedules of Central Power and Light Company and subsidiary, Public Service Company of Oklahoma and its subsidiaries, Southwestern Electric Power Company and subsidiaries, and West Texas Utilities Company for the years ended December 31, 1999 and 1998 and the financial information of Central and South West Corporation and its subsidiaries that is included in the financial statement schedule for American Electric Power Company, Inc. and its subsidiaries for the years ended December 31, 1999 and 1998. These financial statement schedules are the responsibility of the respective company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the corresponding basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 26, 2001

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<TABLE>
<CAPTION>

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

COLUMN A	COLUMN B	COLUM
		ADDIT
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES
		(IN THOUSANDS)
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for Uncollectible Accounts:		
Year Ended December 31, 2000.............	$17,066	$14,878
Year Ended December 31, 1999.............	$14,841	$24,165
Year Ended December 31, 1998.............	$ 9,049	$28,809

</TABLE>

<TABLE>
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN D	COLUMN E
DESCRIPTION	DEDUCTIONS	BALANCE AT END OF PERIOD
	(IN THOUSANDS)	

<S> <C> <C>

DEDUCTED FROM ASSETS:		
Accumulated Provision for		
Uncollectible Accounts:		
Year Ended December 31, 2000..............	$21,323(b)	$11,044
	=======	=======
Year Ended December 31, 1999..............	$37,728(b)	$17,066
	=======	=======
Year Ended December 31, 1998..............	$31,347(b)	$14,841
	=======	=======

</TABLE>

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

<TABLE>
<CAPTION>

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

COLUMN A	COLUMN B	COLUM
		ADDIT
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES
		(IN THOUSANDS)
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for		
Uncollectible Accounts:		
Year Ended December 31, 2000..............	$2,609	$6,592
	======	======
Year Ended December 31, 1999..............	$2,234	$5,492
	======	======
Year Ended December 31, 1998..............	$1,333	$5,093
	======	======

</TABLE>

<TABLE>
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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN D	COLUMN E
DESCRIPTION	DEDUCTIONS	BALANCE AT END OF PERIOD
	(IN THOUSANDS)	
<S>	<C>	<C>

DEDUCTED FROM ASSETS:		
Accumulated Provision for		
Uncollectible Accounts:		
Year Ended December 31, 2000..............	$8,139(b)	$2,588
Year Ended December 31, 1999..............	$7,112(b)	$2,609
Year Ended December 31, 1998..............	$5,498(b)	$2,234

</TABLE>

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

<TABLE>
<CAPTION>

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARY
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERV

COLUMN A	COLUMN B	COLUM
		ADDIT
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES
		(IN THOUS
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for		
Uncollectible Accounts:		
Year Ended December 31, 2000..............	$ --	$1,675
Year Ended December 31, 1999..............	$ --	$ --
Year Ended December 31, 1998..............	$ --	$ --

</TABLE>

<TABLE>
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CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARY
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN D	COLUMN E
DESCRIPTION	DEDUCTIONS	BALANCE AT END OF PERIOD
	(IN THOUSANDS)	
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		

Accumulated Provision for Uncollectible Accounts:		
Year Ended December 31, 2000..............	$ -- (b)	$1,675
Year Ended December 31, 1999..............	$ -- (b)	$ --
Year Ended December 31, 1998..............	$ -- (b)	$ --

</TABLE>

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

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<TABLE>
<CAPTION>

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RE

COLUMN A	COLUMN B	COLUM
		ADDIT
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES
		(IN THOUSANDS)
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for Uncollectible Accounts:		
Year Ended December 31, 2000..............	$3,045	$2,082
Year Ended December 31, 1999..............	$2,598	$3,334
Year Ended December 31, 1998..............	$1,058	$7,551

</TABLE>

<TABLE>
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COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN D	COLUMN E
		BALANCE AT

DESCRIPTION	DEDUCTIONS	END OF PERIOD
	(IN THOUSANDS)	
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for		
Uncollectible Accounts:		
Year Ended December 31, 2000..............	$ 5,873(b)	$ 659
Year Ended December 31, 1999..............	$13,669(b)	$3,045
Year Ended December 31, 1998..............	$11,289(b)	$2,598

</TABLE>

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

<TABLE>
<CAPTION>

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

COLUMN A	COLUMN B	COLUM
		ADDIT
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES
		(IN THOUSANDS)
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for		
Uncollectible Accounts:		
Year Ended December 31, 2000..............	$1,848	$ (235)
Year Ended December 31, 1999..............	$2,027	$3,966
Year Ended December 31, 1998..............	$1,188	$4,630

</TABLE>

<TABLE>
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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN D	COLUMN E
		BALANCE AT

DESCRIPTION	DEDUCTIONS	END OF PERIOD
	(IN THOUSANDS)	
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for		
Uncollectible Accounts:		
Year Ended December 31, 2000..............	$1,761(b)	$ 759
Year Ended December 31, 1999..............	$5,512(b)	$1,848
Year Ended December 31, 1998..............	$4,012(b)	$2,027

</TABLE>

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

<TABLE>
<CAPTION>

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

COLUMN A	COLUMN B	COLUM
		ADDIT
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES
		(IN THOUSANDS)
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for		
Uncollectible Accounts:		
Year Ended December 31, 2000..............	$637	$ 187
Year Ended December 31, 1999..............	$848	$1,032
Year Ended December 31, 1998..............	$525	$1,280

</TABLE>

<TABLE>
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KENTUCKY POWER COMPANY
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN D	COLUMN E

DESCRIPTION	DEDUCTIONS	BALANCE AT END OF PERIOD
	(IN THOUSANDS)	
DEDUCTED FROM ASSETS:		
Accumulated Provision for Uncollectible Accounts:		
Year Ended December 31, 2000	$ 551(b)	$282
Year Ended December 31, 1999	$1,710(b)	$637
Year Ended December 31, 1998	$1,349(b)	$848

</TABLE>

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

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<TABLE>
<CAPTION>

OHIO POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUM
		ADDIT
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES
		(IN THOUSANDS)
DEDUCTED FROM ASSETS:		
Accumulated Provision for Uncollectible Accounts:		
Year Ended December 31, 2000	$2,223	$ 472
Year Ended December 31, 1999	$1,678	$4,730
Year Ended December 31, 1998	$2,501	$3,255

</TABLE>

<TABLE>
<CAPTION>

OHIO POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN D	COLUMN E
DESCRIPTION	DEDUCTIONS	BALANCE AT END OF PERIOD
	(IN THOUSANDS)	
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for Uncollectible Accounts:		
Year Ended December 31, 2000..............	$2,419(b)	$1,054
Year Ended December 31, 1999..............	$5,458(b)	$2,223
Year Ended December 31, 1998..............	$5,019(b)	$1,678

</TABLE>

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

<TABLE>
<CAPTION>

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

COLUMN A	COLUMN B	COLUM
		ADDIT
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES
		(IN THOUSANDS)
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for Uncollectible Accounts:		
Year Ended December 31, 2000..............	$ --	$ 467
Year Ended December 31, 1999..............	$ --	$ --
Year Ended December 31, 1998..............	$ --	$ --

</TABLE>

<TABLE>
<CAPTION>

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES

SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN D	COLUMN E
DESCRIPTION	DEDUCTIONS	BALANCE AT END OF PERIOD
	(IN THOUSANDS)	
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for		
Uncollectible Accounts:		
Year Ended December 31, 2000..............	$ -- (b)	$ 467
Year Ended December 31, 1999..............	$ -- (b)	$ --
Year Ended December 31, 1998..............	$ -- (b)	$ --

</TABLE>

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

<TABLE>
<CAPTION>

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUM
		ADDIT
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES
	(IN THOUSANDS)	
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for		
Uncollectible Accounts:		
Year Ended December 31, 2000..............	$4,428	$ 911
Year Ended December 31, 1999..............	$3,269	$5,415
Year Ended December 31, 1998..............	$2,216	$4,547

</TABLE>

<TABLE>
<CAPTION>

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES

SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN D	COLUMN E
DESCRIPTION	DEDUCTIONS	BALANCE AT END OF PERIOD
	(IN THOUSANDS)	
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for Uncollectible Accounts:		
Year Ended December 31, 2000..............	$ -- (b)	$ 911
Year Ended December 31, 1999..............	$ 4,256(b)	$4,428
Year Ended December 31, 1998..............	$ 3,494(b)	$3,269

</TABLE>

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

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<TABLE>
<CAPTION>

WEST TEXAS UTILITIES COMPANY
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUM
		ADDIT
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES
		(IN THOUSANDS)
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for Uncollectible Accounts:		
Year Ended December 31, 2000..............	$186	$1,499
Year Ended December 31, 1999..............	$497	$ (66)
Year Ended December 31, 1998..............	$ 73	$ 616

</TABLE>

<TABLE>

<CAPTION>

WEST TEXAS UTILITIES COMPANY
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN D	COLUMN E
DESCRIPTION	DEDUCTIONS	BALANCE AT END OF PERIOD
	(IN THOUSANDS)	
<S>	<C>	<C>
DEDUCTED FROM ASSETS:		
Accumulated Provision for Uncollectible Accounts:		
Year Ended December 31, 2000..............	$1,443(b)	$288
Year Ended December 31, 1999..............	$ 288(b)	$186
Year Ended December 31, 1998..............	$ 232(b)	$497

</TABLE>

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

EXHIBIT INDEX

Certain of the following exhibits, designated with an asterisk(*), are filed herewith. The exhibits not so designated have heretofore been filed with the Commission and, pursuant to 17 C.F.R. 229.10(d) and 240.12b-32, are incorporated herein by reference to the documents indicated in brackets following the descriptions of such exhibits. 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.

<TABLE>
<CAPTION>

EXHIBIT NUMBER		DESCRIPTION
<S>		<C>
AEGCO		
3(a)	--	Copy of Articles of Incorporation of AEGCo [Registration Statement on Form 10 for the Common Shares of AEGCo, File No. 0-18135, Exhibit 3(a)].
*3(b)	--	Copy of the Code of Regulations of AEGCo (amended as of June 15, 2000).
10(a)	--	Copy of Capital Funds Agreement dated as of December 30, 1988 between AEGCo and AEP [Registration Statement No. 33-32752, Exhibit 28(a)].
10(b)(1)	--	Copy of Unit Power Agreement dated as of March 31, 1982

		between AEGCo and I&M, as amended [Registration Statement No. 33-32752, Exhibits 28(b)(1)(A) and 28(b)(1)(B)].
10(b)(2)	--	Copy of Unit Power Agreement, dated as of August 1, 1984, among AEGCo, I&M and KEPCo [Registration Statement No. 33-32752, Exhibit 28(b)(2)].
10(b)(3)	--	Copy of Agreement, dated as of October 1, 1984, among AEGCo, I&M, APCo and Virginia Electric and Power Company [Registration Statement No. 33-32752, Exhibit 28(b)(3)].
10(c)	--	Copy of Lease Agreements, dated as of December 1, 1989, between AEGCo and Wilmington Trust Company, as amended [Registration Statement No. 33-32752, Exhibits 28(c)(1)(C), 28(c)(2)(C), 28(c)(3)(C), 28(c)(4)(C), 28(c)(5)(C) and 28(c)(6)(C); Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1993, File No. 0-18135, Exhibits 10(c)(1)(B), 10(c)(2)(B), 10(c)(3)(B), 10(c)(4)(B), 10(c)(5)(B) and 10(c)(6)(B)].
*13	--	Copy of those portions of the AEGCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*24	--	Power of Attorney.
AEP++		
3(a)	--	Copy of Restated Certificate of Incorporation of AEP, dated October 29, 1997 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1997, File No. 1-3525, Exhibit 3(a)].
3(b)	--	Copy of Certificate of Amendment of the Restated Certificate of Incorporation of AEP, dated January 13, 1999 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 3(b)].
3(c)	--	Composite copy of the Restated Certificate of Incorporation of AEP, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 3(c)].
3(d)	--	Copy of By-Laws of AEP, as amended through January 28, 1998 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 3(b)].
10(a)	--	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, OPCo and I&M and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(b)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525,

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EXHIBIT NUMBER	DESCRIPTION
<S>	<C>
AEP++ (continued)	
	Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525,

		Exhibit 10(b)(2)].
10(c)	--	Copy of Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended [Registration Statement No. 33-32752, Exhibits 28(c)(1)(C), 28(c)(2)(C), 28(c)(3)(C), 28(c)(4)(C), 28(c)(5)(C) and 28(c)(6)(C); Registration Statement No. 33-32753, Exhibits 28(a)(1)(C), 28(a)(2)(C), 28(a)(3)(C), 28(a)(4)(C), 28(a)(5)(C) and 28(a)(6)(C); and Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1993, File No. 0-18135, Exhibits 10(c)(1)(B), 10(c)(2)(B), 10(c)(3)(B), 10(c)(4)(B), 10(c)(5)(B) and 10(c)(6)(B); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibits 10(e)(1)(B), 10(e)(2)(B), 10(e)(3)(B), 10(e)(4)(B), 10(e)(5)(B) and 10(e)(6)(B)].
10(d)	--	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested) [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 10(l)(2)].
10(e)	--	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
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 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(f)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of AEP dated December 15, 1999, File No. 1-3525, Exhibit 10].
+10(g)(1)	--	AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(e)].
+10(g)(2)	--	Amendment to AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1986, File No. 1-3525, Exhibit 10(d)(2)].
+10(h)	--	AEP Accident Coverage Insurance Plan for directors [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(g)].
*+10(i)(1)	--	AEP Deferred Compensation and Stock Plan for Non-Employee Directors, as amended June 1, 2000.
*+10(i)(2)	--	AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended June 1, 2000.
*+10(j)(1)(A)	--	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.
+10(j)(1)(B)	--	Guaranty by AEP of the Service Corporation Excess Benefits Plan [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(h)(1)(B)].
*+10(j)(2)	--	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2001 (Non-Qualified).
+10(j)(3)	--	Service Corporation Umbrella Trust for Executives [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
+10(k)	--	Employment Agreement between E. Linn Draper, Jr. and

		AEP and the Service Corporation [Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1991, File No. 0-18135, Exhibit 10(g)(3)].
+10(l)	--	AEP System Senior Officer Annual Incentive Compensation Plan[Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(i)(1)].

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EXHIBIT NUMBER		DESCRIPTION
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AEP++ (continued)		
+10(m)	--	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhibit 10].
+10(n)	--	Letter agreement between AEP and Donald M. Clements, Jr. dated August 19, 1994 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(n)].
+10(o)	--	AEP Senior Executive Severance Plan for Merger with Central and South West Corporation, effective March 1, 1999 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(o)].
+10(p)	--	AEP Change In Control Agreement [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1999, File No. 1-3525, Exhibit 10(p)].
+10(q)	--	AEP System 2000 Long-Term Incentive Plan [Proxy Statement of AEP, March 10, 2000].
*+10(r)(1)	--	Employment Agreement between Paul Addis and the Service Corporation dated January 17, 1996.
*+10(r)(2)	--	Amending Agreement dated July 30, 1998 to Employment Agreement of Paul Addis.
*+10(r)(3)	--	AEP Energy Services Incentive Compensation Plan.
*+10(r)(4)	--	AEP Energy Services Phantom Equity Plan.
*+10(s)	--	Memorandum of agreement between Susan Tomasky and the Service Corporation dated January 3, 2001.
*13	--	Copy of those portions of the AEP 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*21	--	List of subsidiaries of AEP.
*23(a)	--	Consent of Deloitte & Touche LLP.
*23(b)	--	Consent of Arthur Andersen LLP.
*23(c)	--	Consent of KPMG Audit plc.
*24	--	Power of Attorney.
APCO++		
3(a)	--	Copy of Restated Articles of Incorporation of APCo, and amendments thereto to November 4, 1993 [Registration Statement No. 33-50163, Exhibit 4(a); Registration Statement No. 33-53805, Exhibits 4(b) and 4(c)].
3(b)	--	Copy of Articles of Amendment to the Restated Articles of Incorporation of APCo, dated June 6, 1994 [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1994, File No. 1-3457, Exhibit 3(b)].
3(c)	--	Copy of Articles of Amendment to the Restated Articles of Incorporation of APCo, dated March 6, 1997 [Annual

		Report on Form 10-K of APCo for the fiscal year ended December 31, 1996, File No. 1-3457, Exhibit 3(c)].
3(d)	--	Composite copy of the Restated Articles of Incorporation of APCo (amended as of March 7, 1997) [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1996, File No. 1-3457, Exhibit 3(d)].
*3(e)	--	Copy of By-Laws of APCo (amended as of June 15, 2000).
4(a)	--	Copy of 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, Exhibit 7(b); Registration Statement No. 2-19884, Exhibit 2(1); Registration Statement No. 2-24453, Exhibit2(n); Registration Statement No. 2-60015, Exhibits 2(b)(2), 2(b)(3), 2(b)(4), 2(b)(5), 2(b)(6), 2(b)(7), 2(b)(8), 2(b)(9), 2(b)(10), 2(b)(12), 2(b)(14), 2(b)(15), 2(b)(16), 2(b)(17), 2(b)(18), 2(b)(19), 2(b)(20), 2(b)(21), 2(b)(22), 2(b)(23), 2(b)(24), 2(b)(25), 2(b)(26), 2(b)(27) and 2(b)(28); Registration Statement No. 2-64102, Exhibit 2(b)(29); Registration Statement No. 2-66457, Exhibits (2)(b)(30) and 2(b)(31); Registration Statement No. 2-69217, Exhibit 2(b)(32); Registration Statement No. 2-86237, Exhibit 4(b); Registration Statement No. 33-11723, Exhibit 4(b); Registration

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EXHIBIT NUMBER		DESCRIPTION
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APCO++ (continued)		
		Statement No. 33-17003, Exhibit 4(a)(ii), Registration Statement No. 33-30964, Exhibit 4(b); Registration Statement No. 33-40720, Exhibit 4(b); Registration Statement No. 33-45219, Exhibit 4(b); Registration Statement No. 33-46128, Exhibits 4(b) and 4(c); Registration Statement No. 33-53410, Exhibit 4(b); Registration Statement No. 33-59834, Exhibit 4(b); Registration Statement No. 33-50229, Exhibits 4(b) and 4(c); Registration Statement No. 33-58431, Exhibits 4(b), 4(c), 4(d) and 4(e); Registration Statement No. 333-01049, Exhibits 4(b) and 4(c); Registration Statement No. 333-20305, Exhibits 4(b) and4(c); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1996, File No. 1-3457, Exhibit 4(b); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1998, File No. 1-3457, Exhibit 4(b)].
4(b)	--	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee [Registration Statement No. 333-45927, Exhibit 4(a); Registration Statement No. 333-49071, Exhibit 4(b); Registration Statement No. 333-84061, Exhibits 4(b) and 4(c); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1999, File No. 1-3457, Exhibit 4(c)].
*4(c)	--	Company Order and Officers' Certificate, dated June 27, 2000, establishing certain terms of the Floating Rate Notes, Series A, due 2001.
10(a)(1)	--	Copy of 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, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	--	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(3)	--	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	--	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, OPCo and I&M and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(c)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	--	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 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 Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].

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EXHIBIT NUMBER		DESCRIPTION
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APCO++ (continued)		
10(e)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K

		of APCo dated December 15, 1999, File No. 1-3457, Exhibit 10].
+10(f)(1)	--	AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(e)].
+10(f)(2)	--	Amendment to AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1986, File No. 1-3525, Exhibit 10(d)(2)].
+10(g)	--	AEP System Senior Officer Annual Incentive Compensation Plan [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(i)(1)].
+10(h)(1)	--	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(1)(A)].
+10(h)(2)	--	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2001 (Non-Qualified) [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(2)].
+10(h)(3)	--	Umbrella Trust for Executives [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
+10(i)	--	Employment Agreement between E. Linn Draper, Jr. and AEP and the Service Corporation [Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1991, File No. 0-18135, Exhibit 10(g)(3)].
+10(j)	--	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhibit 10].
+10(k)	--	AEP Senior Executive Severance Plan for Merger with Central and South West Corporation, effective March 1, 1999[Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(o)].
+10(l)	--	AEP Change In Control Agreement [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1999, File No. 1-3525, Exhibit 10(p)].
+10(m)	--	AEP System 2000 Long-Term Incentive Plan [Proxy Statement of AEP, March 10, 2000].
+10(n)	--	Memorandum of agreement between Susan Tomasky and the Service Corporation dated January 3, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(s)].
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the APCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
21	--	List of subsidiaries of APCo [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 21].
*23	--	Consent of Deloitte & Touche LLP.
*24	--	Power of Attorney.
CPL++ 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 Incorporation, Statements of Registered Office and/or Agent, and Articles of Amendment

to the Articles of Incorporation [Quarterly Report on Form 10-Q of CPL for the quarter ended March 31, 1997, File No. 0-346, Exhibit 3.1].

*3(b) -- By-Laws of CPL (amended as of April 19, 2000).

4(a) -- Indenture of Mortgage or Deed of Trust, dated November 1, 1943, between CPL and The First National Bank of Chicago and R. D. Manella, as Trustees, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.01; Registration

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EXHIBIT NUMBER — DESCRIPTION

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CPL++ (continued)

Statement No. 2-62271, Exhibit 2.02; Form U-1 No. 70-7003, Exhibit 17; Registration Statement No. 2-98944, Exhibit 4 (b); Form U-1 No. 70-7236, Exhibit 4; Form U-1 No. 70-7249, Exhibit 4; Form U-1 No. 70-7520, Exhibit 2; Form U-1 No. 70-7721, Exhibit 3; Form U-1 No. 70-7725, Exhibit 10; Form U-1 No. 70-8053, Exhibit 10 (a); Form U-1 No. 70-8053, Exhibit 10 (b); Form U-1 No. 70-8053, Exhibit 10 (c); Form U-1 No. 70-8053, Exhibit 10 (d); Form U-1 No. 70-8053, Exhibit 10 (e); Form U-1 No. 70-8053, Exhibit 10 (f)].

4(b) -- CPL-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of CPL:

(1) Indenture, dated as of May 1, 1997, between CPL and the Bank of New York, as Trustee [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibits 4.1 and 4.2].

(2) Amended and Restated Trust Agreement of CPL Capital I, dated as of May 1, 1997, among CPL, as Depositor, the Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustee [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibit 4.3].

(3) Guarantee Agreement, dated as of May 1, 1997, delivered by CPL for the benefit of the holders of CPL Capital I's Preferred Securities [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibit 4.4].

(4) Agreement as to Expenses and Liabilities dated as of May 1, 1997, between CPL and CPL Capital I [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibit 4.5].

*4(c) -- Indenture (for unsecured debt securities), dated as of November 15, 1999, between CPL and The Bank of New York, as Trustee.

*4(d) -- First Supplemental Indenture, dated as of November 15, 1999, between CPL and The Bank of New York, as Trustee, for Floating Rate Notes due November 23, 2001.

*4(e) -- Second Supplemental Indenture, dated as of February 16, 2000, between CPL and The Bank of New York, as Trustee, for Floating Rate Notes due February 22, 2002.

*12 -- Statement re: Computation of Ratios.

*13 -- Copy of those portions of the CPL 2000 Annual Report

		(for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*23(a)	--	Consent of Deloitte & Touche LLP.
*23(b)	--	Consent of Arthur Andersen LLP.
*24	--	Power of Attorney.
CSPCO++		
3(a)	--	Copy of Amended Articles of Incorporation of CSPCo, as amended to March 6, 1992 [Registration Statement No. 33-53377, Exhibit 4(a)].
3(b)	--	Copy of Certificate of Amendment to Amended Articles of Incorporation of CSPCo, dated May 19, 1994 [Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1994, File No. 1-2680, Exhibit 3(b)].
3(c)	--	Composite copy of Amended Articles of Incorporation of CSPCo, as amended [Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1994, File No. 1-2680, Exhibit 3(c)].
3(d)	--	Copy of Code of Regulations and By-Laws of CSPCo [Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1987, File No. 1-2680, Exhibit 3(d)].
4(a)	--	Copy of Indenture of Mortgage and Deed of Trust, dated September 1, 1940, between CSPCo and City Bank Farmers Trust Company (now Citibank, N.A.), as trustee, as supplemented and amended [Registration Statement No. 2-59411, Exhibits 2(B) and 2(C); Registration Statement No. 2-80535, Exhibit 4(b); Registration Statement No. 2-87091, Exhibit 4(b); Registration Statement No. 2-93208, Exhibit 4(b); Registration Statement No. 2-97652, Exhibit 4(b); Registration Statement No. 33-7081, Exhibit 4(b); Registration Statement No. 33-12389, Exhibit 4(b); Registration Statement No.

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EXHIBIT NUMBER		DESCRIPTION
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CSPCO++ (continued)		
		33-19227, Exhibits 4(b), 4(e), 4(f), 4(g) and 4(h); Registration Statement No. 33-35651, Exhibit 4(b); Registration Statement No. 33-46859, Exhibits 4(b) and 4(c); Registration Statement No. 33-50316, Exhibits 4(b) and 4(c); Registration Statement No. 33-60336, Exhibits 4(b), 4(c) and 4(d); Registration Statement No. 33-50447, Exhibits 4(b) and 4(c); Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1993, File No. 1-2680, Exhibit 4(b)].
4(b)	--	Copy of Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo and Bankers Trust Company, as Trustee [Registration Statement No. 333-54025, Exhibits 4(a), 4(b), 4(c) and 4(d); Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1998, File No. 1-2680, Exhibits 4(c) and 4(d)].
10(a)(1)	--	Copy of 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, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	--	Copy of Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(3)	--	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	--	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, OPCo and I&M and the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(c)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo, and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	--	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 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 Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(e)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of CSPCo dated December 15, 1999, File No. 1-2680, Exhibit 10].
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the CSPCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*23	--	Consent of Deloitte & Touche LLP.
*24	--	Power of Attorney.

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EXHIBIT NUMBER	DESCRIPTION

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I&M++		
3(a)	--	Copy of the Amended Articles of Acceptance of I&M and amendments thereto [Annual Report on Form 10-K of I&M for fiscal year ended December 31, 1993, File No. 1-3570, Exhibit 3(a)].
3(b)	--	Copy of Articles of Amendment to the Amended Articles of Acceptance of I&M, dated March 6, 1997 [Annual Report on Form 10-K of I&M for fiscal year ended December 31, 1996, File No. 1-3570, Exhibit 3(b)].
3(c)	--	Composite Copy of the Amended Articles of Acceptance of I&M (amended as of March 7, 1997) [Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1996, File No. 1-3570, Exhibit 3(c)].
3(d)	--	Copy of the By-Laws of I&M (amended as of January 1, 1996) [Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1995, File No. 1-3570, Exhibit 3(c)].
4(a)	--	Copy of Mortgage and Deed of Trust, dated as of June 1, 1939, between I&M and Irving Trust Company (now The Bank of New York) and various individuals, as Trustees, as amended and supplemented [Registration Statement No. 2-7597, Exhibit 7(a); Registration Statement No. 2-60665, Exhibits 2(c)(2), 2(c)(3), 2(c)(4), 2(c)(5), 2(c)(6), 2(c)(7), 2(c)(8), 2(c)(9), 2(c)(10), 2(c)(11), 2(c)(12), 2(c)(13), 2(c)(14), 2(c)(15), (2)(c)(16), and 2(c)(17); Registration Statement No. 2-63234, Exhibit 2(b)(18); Registration Statement No. 2-65389, Exhibit 2(a)(19); Registration Statement No. 2-67728, Exhibit 2(b)(20); Registration Statement No. 2-85016, Exhibit 4(b); Registration Statement No. 33-5728, Exhibit 4(c); Registration Statement No. 33-9280, Exhibit 4(b); Registration Statement No. 33-11230, Exhibit 4(b); Registration Statement No. 33-19620, Exhibits 4(a)(ii), 4(a)(iii), 4(a)(iv) and 4(a)(v); Registration Statement No. 33-46851, Exhibits 4(b)(i), 4(b)(ii) and 4(b)(iii); Registration Statement No. 33-54480, Exhibits 4(b)(I) and 4(b)(ii); Registration Statement No. 33-60886, Exhibit 4(b)(I); Registration Statement No. 33-50521, Exhibits 4(b)(I), 4(b)(ii) and 4(b)(iii); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibit 4(b); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1994, File No. 1-3570, Exhibit 4(b); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1996, File No. 1-3570, Exhibit 4(b)].
4(b)	--	Copy of 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, Exhibits 4(a), 4(b) and 4(c); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1999, File No. 1-3570, Exhibit 4(c)].
* 4(c)	--	Copy of Company Order and Officers' Certificate, dated August 31, 2000, establishing certain terms of the Floating Rate Notes, Series B, due 2002.
10(a)(1)	--	Copy of 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, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit

		5(a)(1)(D); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	--	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].

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EXHIBIT NUMBER		DESCRIPTION
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I&M++ (CONTINUED)		
10(a)(3)	--	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(a)(4)	--	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(5)	--	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	--	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, I&M, and OPCo and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(c)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	--	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 1, 1996, File No. 1-3525, Exhibit 10(l)].
10(e)	--	Copy of Nuclear Material Lease Agreement, dated as of December 1, 1990, between I&M and DCC Fuel Corporation [Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibit 10(d)].
10(f)	--	Copy of Lease Agreements, dated as of December 1,

		1989, between I&M and Wilmington Trust Company, as amended [Registration Statement No. 33-32753, Exhibits 28(a)(1)(C), 28(a)(2)(C), 28(a)(3)(C), 28(a)(4)(C), 28(a)(5)(C) and 28(a)(6)(C); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibits 10(e)(1)(B), 10(e)(2)(B), 10(e)(3)(B), 10(e)(4)(B), 10(e)(5)(B) and 10(e)(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 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(g)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of I&M dated December 15, 1999, File No. 1-3570, Exhibit 10].
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the I&M 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
21	--	List of subsidiaries of I&M [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 21].
*24	--	Power of Attorney.
KEPCO++		
3(a)	--	Copy of Restated Articles of Incorporation of KEPCo [Annual Report on Form 10-K of KEPCo for the fiscal year ended December 31, 1991, File No. 1-6858, Exhibit 3(a)].
*3(b)	--	Copy of By-Laws of KEPCo (amended as of June 15, 2000).

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EXHIBIT NUMBER		DESCRIPTION
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KEPCO++ (CONTINUED)		
4(a)	--	Copy of Mortgage and Deed of Trust, dated May 1, 1949, between KEPCo and Bankers Trust Company, as supplemented and amended [Registration Statement No. 2-65820, Exhibits 2(b)(1), 2(b)(2), 2(b)(3), 2(b)(4), 2(b)(5), and 2(b)(6); Registration Statement No. 33-39394, Exhibits 4(b) and 4(c); Registration Statement No. 33-53226, Exhibits 4(b) and 4(c); Registration Statement No. 33-61808, Exhibits 4(b) and 4(c), Registration Statement No. 33-53007, Exhibits 4(b), 4(c) and 4(d)].
4(b)	--	Copy of Indenture (for unsecured debt securities), dated as of September 1, 1997, between KEPCo and Bankers Trust Company, as Trustee [Registration Statement No. 333-75785, Exhibits 4(a), 4(b), 4(c) and 4(d); Annual Report on Form 10-K of KEPCo for the fiscal year ended December 31, 1999, File No. 1-6858, Exhibit 4(c)].
*4(c)	--	Copy of Company Order and Officers' Certificate, dated November 17, 2000, establishing certain terms of the Floating Rate Notes, Series B, due 2002.
10(a)	--	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, I&M and OPCo and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a);Registration Statement No.

		2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(b)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(c)	--	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
10(d)(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 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(d)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of KEPCo dated December 15, 1999, File No. 1-6858, Exhibit 10].
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the KEPCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*24	--	Power of Attorney.
OPCO++		
3(a)	--	Copy of Amended Articles of Incorporation of OPCo, and amendments thereto to December 31, 1993 [Registration Statement No. 33-50139, Exhibit 4(a); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1993, File No. 1-6543, Exhibit 3(b)].
3(b)	--	Certificate of Amendment to Amended Articles of Incorporation of OPCo, dated May 3, 1994 [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 3(b)].
3(c)	--	Copy of Certificate of Amendment to Amended Articles of Incorporation of OPCo, dated March 6, 1997 [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1996, File No. 1-6543, Exhibit 3(c)].
3(d)	--	Composite copy of the Amended Articles of Incorporation of OPCo (amended as of March 7, 1997) [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1996, File No. 1-6543, Exhibit 3(d)].
3(e)	--	Copy of Code of Regulations of OPCo [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1990, File No. 1-6543, Exhibit 3(d)].

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EXHIBIT NUMBER		DESCRIPTION
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OPCO++ (CONTINUED)		
4(a)	--	Copy of Mortgage and Deed of Trust, dated as of

October 1, 1938, between OPCo and Manufacturers Hanover Trust Company (now Chemical Bank), as Trustee, as amended and supplemented [Registration Statement No. 2-3828, Exhibit B-4; Registration Statement No. 2-60721, Exhibits 2(c)(2), 2(c)(3), 2(c)(4), 2(c)(5), 2(c)(6), 2(c)(7), 2(c)(8), 2(c)(9), 2(c)(10), 2(c)(11), 2(c)(12), 2(c)(13), 2(c)(14), 2(c)(15), 2(c)(16), 2(c)(17), 2(c)(18), 2(c)(19), 2(c)(20), 2(c)(21), 2(c)(22), 2(c)(23), 2(c)(24), 2(c)(25), 2(c)(26), 2(c)(27), 2(c)(28), 2(c)(29), 2(c)(30), and 2(c)(31); Registration Statement No. 2-83591, Exhibit 4(b); Registration Statement No. 33-21208, Exhibits 4(a)(ii), 4(a)(iii) and 4(a)(iv); Registration Statement No. 33-31069, Exhibit 4(a)(ii); Registration Statement No. 33-44995, Exhibit 4(a)(ii); Registration Statement No. 33-59006, Exhibits 4(a)(ii), 4(a)(iii) and 4(a)(iv); Registration Statement No. 33-50373, Exhibits 4(a)(ii), 4(a)(iii) and 4(a)(iv); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1993, File No. 1-6543, Exhibit 4(b)].

4(b)	--	Copy of Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company, as Trustee [Registration Statement No. 333-49595, Exhibits 4(a), 4(b) and 4(c); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1998, File No. 1-6543, Exhibits 4(c) and 4(d); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1999, File No. 1-6543, Exhibits 4(c) and 4(d)].
*4(c)	--	Copy of Company Order and Officers' Certificate, dated May 22, 2000, establishing certain terms of the Floating Rate Notes, Series A, due 2001.
10(a)(1)	--	Copy of 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, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	--	Copy of Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(3)	--	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	--	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, I&M and OPCo and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File 1-3525, Exhibit 10(a)(3)].
10(c)	--	Copy of Transmission Agreement, dated April 1, 1984,

		among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	--	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].

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EXHIBIT NUMBER		DESCRIPTION
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OPCO++ (CONTINUED)		
10(e)	--	Copy of Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1993, File No. 1-6543, Exhibit 10(f)].
10(f)	--	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested) [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 10(l)(2)].
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 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(g)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of OPCo dated December 15, 1999, File No. 1-6543, Exhibit 10].
+10(h)(1)	--	AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(e)].
+10(h)(2)	--	Amendment to AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1986, File No. 1-3525, Exhibit 10(d)(2)].
+10(i)	--	AEP System Senior Officer Annual Incentive Compensation Plan [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(i)(1)].
+10(j)(1)	--	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(1)(A)].
+10(j)(2)	--	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2001 (Non-Qualified) [Annual Report on Form 10-K of AEP for

		the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(2)].
+10(j)(3)	--	Umbrella Trust for Executives [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
+10(k)	--	Employment Agreement between E. Linn Draper, Jr. and AEP and the Service Corporation [Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1991, File No. 0-18135, Exhibit 10(g)(3)].
+10(l)	--	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhibit 10].
+10(m)	--	AEP Senior Executive Severance Plan for Merger with Central and South West Corporation, effective March 1, 1999[Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(o)].
+10(n)	--	AEP Change In Control Agreement [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1999, File No. 1-3525, Exhibit 10(p)].
+10(o)	--	AEP System 2000 Long-Term Incentive Plan [Proxy Statement of AEP, March 10, 2000].
+10(p)	--	Memorandum of agreement between Susan Tomasky and the Service Corporation dated January 3, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(s)].
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the OPCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
21	--	List of subsidiaries of OPCo [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 21].
*23	--	Consent of Deloitte & Touche LLP.

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EXHIBIT NUMBER		DESCRIPTION
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OPCO++ (CONTINUED)		
*24	--	Power of Attorney.
PSO++		
3(a)	--	Restated Certificate of Incorporation of PSO [Annual Report on Form U5S of Central and South West Corporation for the fiscal year ended December 31, 1996, File No. 1-1443, Exhibit B-3.1].
*3(b)	--	By-Laws of PSO (amended as of June 28, 2000).
4(a)	--	Indenture, dated July 1, 1945, between PSO and Liberty Bank and Trust Company of Tulsa, National Association, as Trustee, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.03; Registration Statement No. 2-64432, Exhibit 2.02; Registration Statement No. 2-65871, Exhibit 2.02; Form U-1 No. 70-6822, Exhibit 2; Form U-1 No. 70-7234, Exhibit 3; Registration Statement No. 33-48650, Exhibit 4(b); Registration Statement No. 33-49143, Exhibit 4(c); Registration Statement No. 33-49575, Exhibit 4(b); Annual Report on Form 10-K of PSO for the fiscal year ended

		December 31, 1993, File No. 0-343, Exhibit 4(b); Current Report on Form 8-K of PSO dated March 4, 1996, No. 0-343, Exhibit 4.01; Current Report on Form 8-K of PSO dated March 4, 1996, No. 0-343, Exhibit 4.02; Current Report on Form 8-K of PSO dated March 4, 1996, No. 0-343, Exhibit 4.03].
4(b)	--	PSO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of PSO: (1) Indenture, dated as of May 1, 1997, between PSO and The Bank of New York, as Trustee [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibits 4.6 and 4.7]. (2) Amended and Restated Trust Agreement of PSO Capital I, dated as of May 1, 1997, among PSO, as Depositor, The Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustee [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibit 4.8]. (3) Guarantee Agreement, dated as of May 1, 1997, delivered by PSO for the benefit of the holders of PSO Capital I's Preferred Securities [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibits 4.9]. (4) Agreement as to Expenses and Liabilities, dated as of May 1, 1997, between PSO and PSO Capital I [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibits 4.10].
*4(c)	--	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.
*4(d)	--	First Supplemental Indenture, dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee, for Floating Rate Notes, Series A, due November 21, 2002.
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the PSO 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*23(a)	--	Consent of Deloitte & Touche LLP.
*23(b)	--	Consent of Arthur Andersen LLP.
*24	--	Power of Attorney.
SWEPCO++		
3(a)	--	Restated Certificate of Incorporation, as amended through May 6, 1997, including Certificate of Amendment of Restated Certificate of Incorporation [Quarterly Report on Form 10-Q of SWEPCo for the quarter ended March 31, 1997, File No. 1-3146, Exhibit 3.4].
3(b)	--	By-Laws of SWEPCo (amended as of April 27, 2000) [Quarterly Report on Form 10-Q of SWEPCo for the quarter ended March 31, 2000, File No. 1-3146, Exhibit 3.3].

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EXHIBIT NUMBER		DESCRIPTION
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SWEPCO++ (CONTINUED)		

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, Exhibit 5.04; Registration Statement No. 2-61943, Exhibit 2.02; Registration Statement No. 2-66033, Exhibit 2.02; Registration Statement No. 2-71126, Exhibit 2.02; Registration Statement No. 2-77165, Exhibit 2.02; Form U-1 No. 70-7121, Exhibit 4; Form U-1 No. 70-7233, Exhibit 3; Form U-1 No. 70-7676, Exhibit 3; Form U-1 No. 70-7934, Exhibit 10; Form U-1 No. 72-8041, Exhibit 10(b); Form U-1 No. 70-8041, Exhibit 10(c); Form U-1 No. 70-8239, Exhibit 10(a)].
4(b)	--	SWEPCO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCO: (1) Indenture, dated as of May 1, 1997, between SWEPCO and the Bank of New York, as Trustee [Quarterly Report on Form 10-Q of SWEPCO dated March 31, 1997, File No. 1-3146, Exhibits 4.11 and 4.12]. (2) Amended and Restated Trust Agreement of SWEPCO Capital I, dated as of May 1, 1997, among SWEPCO, as Depositor, the Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustee [Quarterly Report on Form 10-Q of SWEPCO dated March 31, 1997, File No. 1-3146, Exhibit 4.13]. (3) Guarantee Agreement, dated as of May 1, 1997, delivered by SWEPCO for the benefit of the holders of SWEPCO Capital I's Preferred Securities [Quarterly Report on Form 10-Q of SWEPCO dated March 31, 1997, File No. 1-3146, Exhibit 4.14]. (4) Agreement as to Expenses and Liabilities, dated as of May 1, 1997 between SWEPCO and SWEPCO Capital I [Quarterly Report on Form 10-Q of SWEPCO dated March 31, 1997, File No. 1-3146, Exhibits 4.15].
*4(c)	--	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCO and The Bank of New York, as Trustee.
*4(d)	--	First Supplemental Indenture, dated as of February 25, 2000, between SWEPCO and The Bank of New York, as Trustee, for Floating Rate Notes due March 1, 2001.
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the SWEPCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*23(a)	--	Consent of Deloitte & Touche LLP.
*23(b)	--	Consent of Arthur Andersen LLP.
*24	--	Power of Attorney.
WTU++		
3(a)	--	Restated Articles of Incorporation, as amended, and Articles of Amendment to the Articles of Incorporation [Annual Report on Form 10-K of WTU for the fiscal year ended December 31, 1996, File No. 0-340, Exhibit 3.5].
3(b)	--	By-Laws of WTU (amended as of May 1, 2000) [Quarterly Report on Form 10-Q of WTU for the quarter ended March 31, 2000, File No. 0-340, Exhibit 3.4].
4(a)	--	Indenture, dated August 1, 1943, between WTU and Harris Trust and Savings Bank and J. Bartolini, as Trustees, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.05; Registration Statement No. 2-63931, Exhibit 2.02; Registration Statement No. 2-74408, Exhibit 4.02; Form U-1 No. 70-6820, Exhibit 12; Form U-1 No. 70-6925, Exhibit 13;

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                          Registration Statement No. 2-98843, Exhibit 4(b); Form
                          U-1 No. 70-7237, Exhibit 4; Form U-1 No. 70-7719, Exhibit
                          3; Form U-1 No. 70-7936, Exhibit 10; Form U-1 No.
                          70-8057, Exhibit 10; Form U-1 No. 70-8265, Exhibit 10;
                          Form U-1 No. 70-8057, Exhibit 10(b); Form U-1 No.
                          70-8057, Exhibit 10(c)].
  *12                 --  Statement re: Computation of Ratios.
  *13                 --  Copy of those portions of the WTU 2000 Annual Report
                          (for the fiscal year ended December 31, 2000) which are
                          incorporated by reference in this filing.
</TABLE>

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EXHIBIT NUMBER                                  DESCRIPTION
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<S>                       <C>
WTU++ (CONTINUED)
  *24                 --  Power of Attorney.
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++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.

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