Indiana Michigan
Power Company
500 Circle Drive
Buchanan, MI 49107 1373

INDIANA MICHIGAN POWER

May 24, 2004

AEP:NRC:4071-01
10 CFR 50.71(b)
10 CFR 140.21(e)

Docket Nos.: 50-315
50-316

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop O-P1-17
Washington, D.C. 20555-0001

Donald C. Cook Nuclear Plant Units 1 and 2
2003 FINANCIAL INFORMATION FOR
INDIANA MICHIGAN POWER COMPANY

In accordance with 10 CFR 50.71(b), Attachment 1 to this letter provides the Indiana Michigan Power Company (I&M) 2003 Annual Financial Report. Attachment 2 provides a copy of the year 2004 projected cash flow for I&M as required by 10 CFR 140.21(e).

This letter contains no new commitments. Should you have any questions, please contact Mr. Michael K. Scarpello, Supervisor of Nuclear Licensing, at (269) 697-5020.

Sincerely,

John A. Zwolinski
Director of Design Engineering and Regulatory Affairs

DB/rdw

Attachments

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ATTACHMENT 1 TO AEP:NRC:4071-01

INDIANA MICHIGAN POWER COMPANY
2003 ANNUAL REPORT

Sections B through F and Sections H through K have been omitted from this attachment in order to provide only information relevant to the Licensee, Indiana Michigan Power Company.

2003 Annual Reports

American Electric Power Company, Inc.

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

Audited Financial Statements and
Management's Discussion and Analysis

AEP AMERICAN ELECTRIC POWER

AEP: America's Energy Partner®

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
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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 other true-up items and the recovery of such amounts.
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEPR.
AEPR	AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System Power Pool or AEP 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.
AEP West companies	PSO, SWEPCo, TCC and TNC.
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.
ALJ	Administrative Law Judge.
Alliance RTO	Alliance Regional Transmission Organization, an ISO formed by AEP and four unaffiliated utilities (the FERC overturned earlier approvals of this RTO in December 2001).
Amos Plant	John E. Amos Plant, a 2,900 MW generation station jointly owned and operated by APCo and OPCo.
APB 18	Accounting Principles Board Opinion Number 18: The Equity Method of Accounting for Investments in Common Stock.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Arkansas Commission	Arkansas Public Service Commission.
Buckeye	Buckeye Power, 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.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW 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.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
ECOM	Excess Cost Over Market.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.

EITF 02-3	Emerging Issues Task Force Issue No. 02-3: Issues Involved in Accounting for Derivative Contracts Held For Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.
ERCOT	The Electric Reliability Council of Texas.
EWGs	Exempt Wholesale Generators.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 45	FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities."
FUCOs	Foreign Utility Companies.
GAAP	Generally Accepted Accounting Principles.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
ICR	Interchange Cost Reconstruction.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
ISO	Independent System Operator.
JMG	JMG Funding LP.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KV	Kilovolt.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, an AEP subsidiary.
LPSC	Louisiana Public Service Commission.
Michigan Legislation	The Customer Choice and Electricity Reliability Act, a Michigan law which provides for customer choice of electricity supplier.
MISO	Midwest Independent System Operator (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.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NOx	Nitrogen oxide.
NOx Rule	A final rule issued by Federal EPA which requires NOx reductions in 22 eastern states including seven of the states in which AEP companies operate.
NRC	Nuclear Regulatory Commission.
OCC	The Corporation Commission of the State of Oklahoma.
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.
PTB	Price-to-Beat.
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.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Retail Electric Provider.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges, and non-derivative contracts held for trading purposes that were subject to mark-to-market accounting prior to January 1, 2003.
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, <u>Accounting for the Effects of Certain Types of Regulation</u>.
SFAS 101	Statement of Financial Accounting Standards No. 101, <u>Accounting for the Discontinuance of Application of Statement 71</u>.
SFAS 133	Statement of Financial Accounting Standards No. 133, <u>Accounting for Derivative Instruments and Hedging Activities</u>.
SFAS 143	Statement of Financial Accounting Standards No. 143, <u>Accounting for Asset Retirement Obligations</u>.
SFAS 149	Statement of Financial Accounting Standards No. 149, <u>Amendment of Statement 133 on Derivative Instruments and Hedging Activities</u>.
SFAS 150	Statement of Financial Accounting Standards No. 150, <u>Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity</u>.
SNF	Spent Nuclear Fuel.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by AEP Texas Central 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 TCC.
Superfund	The Comprehensive Environmental, Response, Compensation and Liability Act.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Tenor	Maturity of a contract.
Texas Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
TVA	Tennessee Valley Authority.
U.K.	The United Kingdom.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WVPSC	Public Service Commission of West Virginia.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
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.

FORWARD-LOOKING INFORMATION

This report made by AEP and certain of its subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its registrant subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Electric load and customer growth.
- Weather conditions.
- Available sources and costs of fuels.
- Availability of generating capacity and the performance of AEP's generating plants.
- The ability to recover regulatory assets and stranded costs in connection with deregulation.
- New legislation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
- Resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for environmental compliance).
- Oversight and/or investigation of the energy sector or its participants.
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- AEP's ability to reduce its operation and maintenance costs.
- The success of disposing of investments that no longer match AEP's corporate profile.
- AEP's ability to sell assets at attractive prices and on other attractive terms.
- International and country-specific developments affecting foreign investments including the disposition of any current foreign investments.
- The economic climate and growth in AEP's service territory and changes in market demand and demographic patterns.
- Inflationary trends.
- AEP's ability to develop and execute on a point of view regarding prices of electricity, natural gas, and other energy-related commodities.
- Changes in the creditworthiness and number of participants in the energy trading market.
- Changes in the financial markets, particularly those affecting the availability of capital and AEP's ability to refinance existing debt at attractive rates.
- Actions of rating agencies, including changes in the ratings of debt and preferred stock.
- Volatility and changes in markets for electricity, natural gas, and other energy-related commodities.
- Changes in utility regulation, including the establishment of a regional transmission structure.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of AEP's pension plan.
- Prices for power that we generate and sell at wholesale.
- Changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

AEP COMMON STOCK AND DIVIDEND INFORMATION

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

Quarter Ended	High	Low	Quarter-end Closing Price	Dividend
December 2003	$30.59	$26.69	$30.51	$0.35
September 2003	30.00	26.58	30.00	0.35
June 2003	31.51	22.56	29.83	0.35
March 2003	30.63	19.01	22.85	0.60
December 2002	$30.55	$15.10	$27.33	$0.60
September 2002	40.37	22.74	28.51	0.60
June 2002	48.80	39.00	40.02	0.60
March 2002	47.08	39.70	46.09	0.60

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2003, AEP had approximately 150,000 registered shareholders.

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES

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

	2003	2002	2001	2000	1999
OPERATIONS STATEMENTS DATA			(in millions)		
Total Revenues	$14,545	$13,308	$12,753	$10,743	$9,695
Operating Income	1,632	1,804	2,223	1,758	2,053
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect	522	485	960	177	865
Discontinued Operations Income (Loss)	(605)	(654)	41	134	116
Extraordinary Losses	-	-	(48)	(44)	(9)
Cumulative Effect of Accounting Changes Gain (Loss)	193	(350)	18	-	-
Net Income (Loss)	110	(519)	971	267	972
BALANCE SHEET DATA			(in millions)		
Property, Plant and Equipment	$36,033	$34,127	$32,993	$31,472	$30,476
Accumulated Depreciation and Amortization	14,004	13,539	12,655	12,398	11,895
Net Property, Plant and Equipment	$22,029	$20,588	$20,338	$19,074	$18,581
Total Assets	$36,744	$35,890	$40,432	$47,703	$36,297
Common Shareholders' Equity	7,874	7,064	8,229	8,054	8,673
Cumulative Preferred Stocks of Subsidiaries (a) (d)	137	145	156	161	182
Trust Preferred Securities (b)	-	321	321	334	335
Long-term Debt (a) (b)	14,101	10,190	9,409	8,980	9,471
Obligations Under Capital Leases (a)	182	228	451	614	610
COMMON STOCK DATA					
Earnings (Loss) per Common Share:					
Before Discontinued Operations, Extraordinary Items and Cumulative Effect	$1.35	$1.46	$2.98	$0.55	$2.69
Discontinued Operations	(1.57)	(1.97)	0.13	0.42	0.36
Extraordinary Losses	-	-	(0.16)	(0.14)	(0.02)
Cumulative Effect of Accounting Changes	0.51	(1.06)	0.06	-	-
Earnings (Loss) Per Share	$0.29	$(1.57)	$3.01	$0.83	$3.03
Average Number of Shares Outstanding (in millions)	385	332	322	322	321
Market Price Range:					
High	$31.51	$48.80	$51.20	$48.94	$48.19
Low	19.01	15.10	39.25	25.94	30.56
Year-end Market Price	30.51	27.33	43.53	46.50	32.13
Cash Dividends on Common (c)	$1.65	$2.40	$2.40	$2.40	$2.40
Dividend Payout Ratio(c)	569.0%	(152.9)%	79.7%	289.2%	79.2%
Book Value per Share	$19.93	$20.85	$25.54	$25.01	$26.96

(a) Including portion due within one year.
(b) See Note 17 of the Notes to Consolidated Financial Statements.
(c) Based on AEP historical dividend rate.
(d) Includes Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption which are classified in 2003 as Non-Current Liabilities.

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

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

We have a vast portfolio of assets including:

- 38,000 megawatts of generating capacity, the largest complement of generation in the U.S., the majority of which has a significant cost advantage in many of our market areas. Utility generating capacity of 4,500 megawatts located in Texas and approximately 280 megawatts of independent power generation located in Colorado and Florida are expected to be sold during 2004
- 39,000 miles of transmission lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 210,000 miles of distribution lines that deliver electricity to customers
- Substantial coal transportation assets (7,000 railcars, 1,800 barges, 37 towboats and two coal handling terminals with 20 million tons of annual capacity)
- 6,400 miles of gas pipelines in Louisiana and Texas with 127 Bcf of gas storage facilities. We have entered into an agreement to sell 2,000 miles of pipeline and plan to sell 9 Bcf of storage located in Louisiana related to our disposal of LIG
- 4,000 megawatts of generating capacity in the U.K., a market which we plan to exit by the end of 2004

BUSINESS STRATEGY

We will continue to concentrate our efforts on our domestic utilities. Our objectives are to be an economical, reliable and safe provider of energy to the markets that we serve. We will achieve economic advantage by designing, building, improving and operating low cost efficient sources of power and maximizing the volumes of power delivered from these facilities. We will maintain and enhance our position as a safe and reliable provider of energy by making significant investments into environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers and that provides a fair return for our shareholders through a stable stream of cash flows enabling us to pay competitive dividends.

We are addressing many challenges in our unregulated business. We have substantially reduced our trading activities that are not related to the sale of power from our owned-generation. We have written down the value of several investments to reflect deterioration in market conditions and sold or plan to sell assets that no longer fit our core business strategy. We have identified certain assets as "held-for-sale" and will move others to "held-for-sale" as we formalize and approve our plans for disposition. We will continue to operate HPL as we evaluate our future plans for this investment.

In summary our business strategy calls for us to:

Operations

- Invest in technology that improves the environment of the communities in which we operate
- Maximize the value of our transmission assets and protect our revenue stream through membership in PJM
- Continue maintaining and improving distribution service quality
- Optimize generation assets by increasing availability and consequently increasing sales
- Complete the sales of our non-core assets

Regulation

- Focus on the regulatory process to maximize our earnings while providing fair and reasonable rates to our customers
- Complete the sale of our generation assets in Texas and recognize and recover the associated stranded costs in compliance with the law
- Complete the integration of the operation of our transmission system into PJM consistent with applicable regulatory requirements

Financial

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

2003 OVERVIEW

2003 was a year of transition for AEP. We repositioned ourselves to take advantage of, and maximize, the value of our utility assets. At the same time we took significant strides to exit non-core investments.

Our utility operations had a year of continued improvement resulting from strong wholesale results and our efforts to control and reduce operating costs. We reduced our losses from unregulated investments by reducing transitional trading losses and cutting related administrative expenses.

During 2003 we further stabilized our financial strength by:

- Issuing approximately $1.1 billion in common stock
- Completing a cost reduction initiative which led to a $392 million decline in operations and maintenance expenses during 2003 as compared to 2002. Savings of approximately $139 million are attributable to our utility operations
- Minimizing future capital requirements associated with non-core assets
- Reducing our cash flow risk by limiting our trading activities to a level consistent with the scope of our generation fleet
- Stabilizing our credit ratings

We have redirected our business strategy by:

- Continuing to streamline our trading activities principally to support the sale of power from our core assets
- Actively pursuing the sale of all of our U.K. generation and our gas pipeline operations located in Louisiana; we expect each of these dispositions to be completed during 2004

OUTLOOK FOR 2004

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

- Continue to identify opportunities to further reduce both our operations and maintenance expenses and to efficiently manage our capital expenditures
- Seek rate changes that are fair and reasonable and that allow us to make the necessary operational and environmental improvements to our system
- Dispose of various unregulated assets to eliminate the negative earnings and cash consequences of these operations
- Use the proceeds from our dispositions to reduce debt and strengthen our capital structure
- Successfully operate certain unregulated investments such as our wind farms and our barge and river transport groups, which compliment our core capabilities
- Evaluate opportunities to hold and operate HPL under a revised business model that reduces commodity risk and earns reasonable returns for shareholders

Our objective is excellence in operations and results. There are, nevertheless, certain risks and challenges. We discuss these matters in detail in the Notes to Financial Statements and later in Management's Discussion and Analysis under the heading of Significant Factors. We will diligently resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our investors.

RESULTS OF OPERATIONS

In 2003, AEP's principal operating business segments and their major activities were:

- Utility Operations:
  - o Domestic generation of electricity for sale to retail and wholesale customers
  - o Domestic electricity transmission and distribution
- Investments-Gas Operations:*
  - o Gas pipeline and storage services
- Investments-UK Operations:**
  - o International generation of electricity for sale to wholesale customers
  - o Coal procurement and transportation to AEP plants and third parties
- Investments-Other:
  - o Coal mining, bulk commodity barging operations and other energy supply related businesses

* Operations of Louisiana Intrastate Gas were classified as discontinued during 2003.
** UK Operations were classified as discontinued during 2003.

American Electric Power Company's consolidated Net Income (Loss) for the years ended December 31, 2003, 2002 and 2001 were as follows (Earnings and Average Shares Outstanding in millions):

	2003		2002		2001	
	Earnings	EPS	Earnings	EPS	Earnings	EPS
Utility Operations	$1,218	$3.17	$1,154	$3.47	$941	$2.92
Investments – Gas Operations	(290)	(.76)	(99)	(.29)	91	.28
Investments – UK Operations	-	-	-	-	-	-
Investments – Other	(277)	(.72)	(522)	(1.58)	-	-
All Other*	(129)	(.34)	(48)	(.14)	(72)	(.22)
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect	522	1.35	485	1.46	960	2.98
Investments – Gas Operations	(91)	(.24)	8	.02	(4)	(.01)
Investments – UK Operations	(507)	(1.32)	(472)	(1.42)	(41)	(.13)
Investments – Other	(7)	(.01)	(190)	(.57)	86	.27
Discontinued Operations	(605)	(1.57)	(654)	(1.97)	41	.13
Extraordinary Loss	-	-	-	-	(48)	(.16)
Cumulative Effect of Accounting Changes	193	.51	(350)	(1.06)	18	.06
Total Net Income (Loss)	$110	$.29	$(519)	$(1.57)	$971	$3.01
Average Shares Outstanding		385		332		322

* All Other includes the parent company interest income and expense, as well as other non-allocated costs.

2003 Compared to 2002

Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect in 2003 increased compared to 2002 due to increased wholesale earnings, lower impairment and other charges, and reduced operations and maintenance expenses. This increase was offset, in part, by milder weather and continuing weakness in the economy. Our Net Income for 2003 of $110 million or $.29 per share includes a loss, net of taxes, on discontinued operations of $605 million and $193 million of income, net of taxes, from the cumulative effect of changing our accounting for asset retirement obligations and for certain trading activities. Our Net Loss for 2002 of $519 million or ($1.57) per share includes a loss, net of taxes, on discontinued operations of $654 million and a $350 million, net of tax, charge for implementing a newly issued accounting pronouncement related to the impairment of goodwill.

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

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

2002 Compared to 2001

Our Net Loss was $519 million or a loss of $1.57 per share in 2002 which was a $1.5 billion decline from 2001. Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect was negatively affected by plant availability, lower wholesale prices, reduced trading activity and write-offs to reduce the valuation of the under-performing assets. In the fourth quarter 2002, we recognized impairments on under-performing assets and recorded losses, net of taxes, of $854 million. The losses in the fourth quarter 2002 were caused by the extended decline in domestic and international energy markets. In addition to the fourth quarter impairment losses, we had losses on discontinued operations of $654 million including U.K. operations, SEEBOARD, Citipower and other investments and a loss for transitional goodwill impairment of $350 million related to SEEBOARD and Citipower that resulted from the adoption of a newly issued accounting standard related to the impairment of goodwill.

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

Utility Operations

Summary of Selected Sales Data
For Utility Operations
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
Energy Summary		(in millions of KWH)	
Retail			
Residential	45,479	46,805	43,498
Commercial	37,104	36,487	35,589
Industrial	51,856	53,686	52,443
Miscellaneous	3,035	3,216	2,208
Total	137,474	140,194	133,738
Wholesale	72,977	70,661	79,288

	2003	2002	2001
Weather Summary		(in degree days)	
Eastern Region			
Actual – Heating	5,314	4,963	4,679
Normal – Heating*	5,182	5,177	5,232
Actual – Cooling	757	1,252	1,021
Normal – Cooling*	975	1,013	997
Western Region			
Actual – Heating	1,020	1,044	1,134
Normal – Heating*	1,062	1,034	1,060
Actual – Cooling	2,220	2,369	2,377
Normal – Cooling*	2,217	2,224	2,233

*Normal Heating/Cooling represents the 30-year average of degree days.

2003 Compared to 2002

Earnings from Utility Operations increased $64 million to $1,218 million in 2003. Decreased operating expenses were partially offset by decreases in revenues net of related fuel and purchased power.

Utility revenues net of related fuel and purchased power decreased as follows:

- Residential demand decreased principally as a consequence of milder weather, and industrial demand was down due to the continued slow economic recovery. The combination of these factors reduced revenues net of related fuel and purchased power by approximately $65 million.
- Reserves for final fuel factor decisions in Texas as well as other disallowances and associated rate reserves of $102 million and lower regulatory deferrals for ECOM-based stranded costs of $44 million reduced earnings. The provisions for stranded cost recovery in Texas recognize a regulatory asset or liability for the difference between the actual price received from the state-mandated auction of 15% of generation capacity and the earlier estimate of market price derived by a PUCT model.
- Fuel and purchased power costs increased by approximately $40 million due in part to nuclear plant outages.
- During the fourth quarter of 2002, we exited trading activities that were not related to the sale of power from our owned-generation. The loss of these contributions from exiting the related trading positions reduced utility earnings by approximately $70 million.

The decreases in utility revenues net of related fuel and purchased power were partially offset as follows:

- Off-system sales, including optimization activities, increased by approximately $160 million primarily due to increased prices and plant availability.
- Transmission revenues increased by approximately $45 million, due principally to increased wholesale power sales volumes.

Utility operating expenses decreased as follows:

- Maintenance and Other Operation expense decreased $139 million due to continuing efforts to reduce costs, primarily labor and insurance, despite severe storm damage in the Midwest.
- Taxes Other Than Income Taxes decreased $17 million primarily due to reduced gross receipts tax as a result of the sale of the Texas REPs.
- Depreciation and Amortization expense decreased $18 million due to the change in our accounting for asset retirement obligations. The accounting change caused similar offsetting increases in Maintenance and Other Operation expenses.

2002 Compared to 2001

Earnings from Utility Operations increased $213 million to $1,154 million in 2002 due to an $84 million gain on the sale of the Texas REPs and capital cost reductions of $104 million, partially offset by a reduction in operating income.

Capital costs decreased due to reductions in short-term interest rates, lower outstanding balances of short-term debt and the refinancing of long-term debt at favorable interest rates. These reductions were partially offset by an increase in the amount of long-term debt outstanding.

Increased operating expenses were partially offset by increases in revenues net of related fuel and purchased power.

Utility revenues net of related fuel and purchased power increased as follows:

- ECOM-based Texas stranded cost deferrals increased $262 million.
- Retail demand increased approximately $180 million due to increased usage by residential customers. Eastern region cooling degree days were up 23% over 2001.

The increases in utility revenues net of related fuel and purchased power were partially offset as follows:

- Off-system sales net of related fuel and purchased power decreased $126 million primarily due to lower plant availability, lower wholesale prices, the loss of certain municipal and co-op customers, and customers switching from FERC tariff-based to market-based rates.
- Trading operations, which decreased $214 million as a result of our previously announced plan to exit trading activities that are not related to the sale of power from our owned-generation.

Utility operating expenses increased as follows:

- Maintenance and Other Operation expense increased $102 million due to increased benefit costs of $48 million, increased post September 11 insurance cost of $35 million and increased nuclear maintenance and other expenses of $19 million.
- Depreciation and Amortization expense increased $46 million as a result of additional generation, transmission and distribution assets.
- Taxes Other Than Income Taxes increased $70 million due to increased property and payroll taxes.

Investments – Gas Operations

2003 Compared to 2002

The loss from our Gas Operations of $290 million increased $191 million from 2002. This increase is primarily due to impairments recorded to reflect the reduction in the value of our gas assets. In the fourth quarter 2003, we recognized impairments and other related charges of $228 million, net of tax, associated with HPL assets and goodwill based on market indicators supported by indicative bids received for LIG. These bids led us to conclude that purchasers were no longer willing to pay higher multiples for historic cash flows which included trading activities. Our previous operating strategy included higher risk tolerances associated with trading activities in order to achieve such operating results.

Partially offsetting the 2003 impairments, gas operations earnings have improved approximately $68 million from 2002 due to a $40 million decrease in losses associated with the options trading portfolio that we are no longer actively trading and exiting through a transition plan (our transition gas trading portfolio) and a $28 million reduction in operating expenses. These earnings improvements were partially offset by $15 million of losses due to unexpected late February 2003 sales to Entex, at fixed prices, when the Houston Ship Channel prices were at historic highs, a decrease in March deliveries due to unseasonably mild weather, and a decline in trading optimization of $28 million due to lower risk tolerances and limits compared to the previous year.

2002 Compared to 2001

The loss from our Gas Operations of $99 million increased $190 million from 2001. The increase is due to significant trading losses in 2002 compared with strong trading results in 2001.

Investments – UK Operations

2003 Compared to 2002

The loss from our UK Operations of $507 million for 2003 increased by $35 million from 2002 and was due primarily to $375 million, net of tax, of impairment and other related charges recorded during the fourth quarter. During 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. As a result, we devalued our UK investment based on bids received from interested unrelated buyers. The loss includes $157 million of pre-tax losses associated with commitments for below market forward sales of power, which are beyond the date of the anticipated sale of these plants. We also experienced operating losses as a result of the deterioration of pretax trading margins of $83 million associated with U.K. power and $29 million associated with coal and freight.

2002 Compared to 2001

Our loss in 2002 from UK Operations of $472 million increased by $431 million from 2001. Our operations in the U.K. were dramatically expanded in December 2001 with the acquisition of two 2,000 MW generation stations. Goodwill and asset impairment charges of $414 million, net of tax, contributed to our 2002 losses. The oversupply conditions throughout 2002 worsened in the fourth quarter after the British government's decision to subsidize British Energy, a financially troubled, dominant generator of power in the U.K. This intervention in the competitive market kept inefficient generation in the marketplace. The write-down of our two U.K. power plants was the result of our analyses that indicated U.K. power prices would not recover to levels that would permit us to carry the plants at their original purchase prices. In addition to unfavorable U.K. power and coal markets, higher than anticipated operating costs contributed to the loss in 2002.

Investments – Other

2003 Compared to 2002

The loss from our Other investments decreased by $245 million to $277 million in 2003. The decrease was primarily due to asset impairment charges of $257 million, net of tax, compared to impairments of $392 million, net of tax, recorded in 2002. 2003 impairments included losses of $45 million, net of tax, for two of our independent generation facilities due to market conditions; $168 million, net of tax, for the Dow facility due to the current market conditions and litigation; and coal mining asset impairments of $44 million, net of tax, based on bids from unrelated parties. Additionally we incurred lower international development costs and reduced interest expenses during 2003.

2002 Compared to 2001

The loss from our Other investment operations of $522 million resulted from $392 million of asset impairment charges, net of tax. These write-downs in the fourth quarter of 2002 recognized the lower valuation in our investments in a utility in Brazil, AEP Communications and other under-performing assets. There were no such write-downs in 2001.

All Other

Our parent company's 2003 expenses increased $81 million over 2002 primarily from higher interest costs due to increased debt at the parent level and reduced reliance on short-term borrowings as well as the recognition of estimated losses from certain litigation contingencies. Expenses in 2002 declined $24 million from 2001 due to lower interest costs.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2003 we improved our financial condition as a consequence of the following actions and events:

- We issued approximately $1.1 billion of new common equity
- We reduced our quarterly dividend in June 2003 to $.35 per share which reduced our annualized cash outflows by approximately $395 million
- We reduced short-term debt by $2.8 billion, restructured our lines of credit into two $750 million facilities, completed approximately $1.3 billion of optional long-term debt redemptions, paid-off $225 million of our Steelhead financing, and funded $1.4 billion of debt maturities
- We limited our energy trading activity to levels necessary to optimize earnings from sales of our owned-generation
- Despite downgrades of certain debt ratings during the first quarter and continued uncertainty in the industry, we have maintained stable credit ratings across the AEP System

Capitalization

	2003	2002	2001
Common Equity	35%	32 %	36%
Preferred Stock	1	1	1
Long-term Debt, including amounts due within one year	63	50	43
Short-term Debt	1	14	17
Minority Interest in Finance Subsidiary	-	3	3
Total Capitalization	100%	100%	100%

Our capital was affected by the following, during 2003:

- We recognized $960 million of impairment losses related to our unregulated investments while reducing our ratio of debt to total capital
- We substantially reduced our short-term debt commitments, thereby reducing refinancing and cash flow risks
- We improved our percentage of common equity outstanding to total capitalization, in part through the issuance of approximately $1.1 billion of new equity.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability due to volatility in wholesale power prices and the effects of credit rating downgrades. We are committed to preserving an adequate liquidity position.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. We had an available liquidity position of approximately $3.5 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Lines of Credit	$ 750	May 2004
Lines of Credit	1,000	May 2005
Lines of Credit	750	May 2006
Euro Revolving Credit Facility	189	October 2004
Letter of Credit Facility	200	September 2006
Total	2,889	
Available Cash and Temporary Investments	920*	
Total Liquidity Sources	3,809	
Less: AEP Commercial Paper Outstanding	282**	
Letters of Credit Outstanding	35	
Net Available Liquidity	$3,492	

* Available Cash and Temporary Investments of $920 million and $262 million in unavailable cash on hand make up the $1.2 billion Cash and Cash Equivalents balance on our Consolidated Balance Sheet at December 31, 2003.

** Amount does not include JMG Funding LP (JMG) commercial paper outstanding in the amount of $26 million. This commercial paper is specifically associated with the Gavin scrubber lease. This commercial paper does not reduce available liquidity to AEP.

Debt Covenants

Our revolving credit agreements require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At December 31, 2003, this percentage was 58.8%. Non-performance of these covenants may result in an event of default under these credit agreements. At December 31, 2003, we complied with the covenants contained in these credit agreements. In addition, the acceleration of the payment obligations of us, or certain of our subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the amounts outstanding thereunder payable.

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

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

Dividend Restrictions

Provisions within the Articles of Incorporation relating to the preferred stock of certain of our subsidiaries restrict the payment of cash dividends or other distributions on their common and preferred stock. PUHCA prohibits our subsidiaries from making loans or advances to the parent company, AEP. In addition, under PUHCA, AEP and its public utility subsidiaries can only pay dividends out of retained or current earnings.

Credit Ratings

We also manage our liquidity by continuing to maintain investment grade credit ratings and a stable credit outlook and are taking steps to improve our credit quality, including plans during 2004 to further reduce our outstanding debt through the use of proceeds from the planned dispositions. If we receive a downgrade in our credit ratings by these agencies, our borrowing costs could increase. The rating agencies currently have AEP and our rated subsidiaries on stable outlook. Current ratings for AEP are as follows:

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

Cash Flow

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

	2003	2002	2001
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$1,199	$194	$232
Net Cash Flows From Operating Activities	2,308	2,067	2,818
Net Cash Flows Used For Investing Activities	(1,888)	(378)	(3,292)
Net Cash Flows (Used For) From Financing Activities	(437)	(681)	437
Effect of Exchange Rate Changes on Cash	-	(3)	(1)
Net Increase (Decrease) in Cash and Cash Equivalents	(17)	1,005	(38)
Cash and Cash Equivalents at End of Period	$1,182	$1,199	$194

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings provide working capital and meet other short-term cash needs. We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a utility money pool which funds the utility subsidiaries and a non-utility money pool which funds the majority of the non-utility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. As of December 31, 2003, we had credit facilities totaling $2.9 billion to support our commercial paper program. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding mechanisms are arranged. Sources of long-term funding include issuance of common stock, preferred stock or long-term debt and sale-leaseback or leasing agreements. Money pool and external borrowings may not exceed SEC authorized limits.

Operating Activities

	2003	2002	2001
		(in millions)	
Net Income (Loss)	$110	$(519)	$971
Plus: Discontinued Operations	605	654	(41)
Income from Continuing Operations	715	135	930
Noncash Items Included in Earnings	1,798	2,734	976
Changes in Assets and Liabilities	(205)	(802)	912
Net Cash Flows From Operating Activities	$2,308	$2,067	$2,818

2003 Operating Cash Flow

Our cash flows from operating activities were $2.3 billion for 2003. We produced income from continuing operations of $715 million during the period. Income from continuing operations for 2003 included noncash items of $1.5 billion for depreciation, amortization, and deferred taxes, $193 million for the cumulative effects of accounting changes, and $720 million for impairment losses and other related charges. In addition, there is a current period impact for a net $122 million balance sheet change for risk management contracts that are marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. Changes in Assets and Liabilities represent those items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are presented below:

- The wholesale capacity auction true-up (ECOM) resulted in stranded cost deferrals of $218 million, which are not recoverable in cash until the conclusion of our Texas true-up proceeding. These proceedings are not expected to be finalized earlier than April 2005.
- Net changes in accounts receivable and accounts payable of $269 million related, in large part, to the settlement of risk management positions during 2002 and payments related to those settlements during 2003. These payments include $90 million in settlement of power and gas transactions to the Williams Companies. The earnings effects of substantially all payments were reflected in earlier periods.
- Increases in inventory levels of $71 million resulting primarily from higher procurement prices.
- Reserves for disallowed fuel costs, principally related to Texas, which will be a component of our 2004 final Texas true-up order of the PUCT.

2002 Operating Cash Flow

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

2001 Operating Cash Flow

Our cash flows from operating activities were $2.8 billion for 2001. Income from continuing operations was $930 million during the period. Income from continuing operations for 2001 included noncash items of $1.5 billion for depreciation, amortization, and deferred taxes, and $18 million related to the cumulative effect of an accounting change. There was a current period impact for a net $294 million balance sheet change for risk management contracts that were marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The activity in the asset and liability accounts was primarily attributable to increased levels of trading activities as compared to 2002 and 2003. During the fourth quarter of 2002 we exited trading that was not related to the sale of power from our owned-generation.

Investing Activities

	2003	2002 (in millions)	2001
Construction Expenditures	$(1,358)	$(1,685)	$(1,646)
Business Acquisitions/Sales Proceeds, net	82	1,263	(621)
Other	(612)	44	(1,025)
Net Cash Flows Used for Investing Activities	$(1,888)	$(378)	$(3,292)

Our cash flows used for investing activities increased $1.5 billion in 2003 from $378 million during the prior year. This increase was due to additional sales proceeds in 2002 related to SEEBOARD, CitiPower, and the Texas REPs as well as increased investments in our U.K. operations during 2003. These increases were partially offset by a reduction of our capital expenditures in 2003 as compared to 2002.

In 2002, our cash flows used for investing activities decreased $2.9 billion from 2001. This decrease resulted from the HPL and UK acquisitions during 2001 as well as the net increase in proceeds received from asset sales during 2002.

We forecast $5.8 billion of construction expenditures for 2004-2006.

Financing Activities

	2003	2002 (in millions)	2001
Issuances of Equity Securities (common stock/equity units)	$1,142	$990	$11
Issuances/Retirements of Debt, net	(727)	(868)	460
Retirement of Preferred Stock	(9)	(10)	(5)
Issuance/Retirement of Minority Interest	(225)	-	744
Dividends	(618)	(793)	(773)
Net Cash Flows (Used for) From Financing Activities	$(437)	$(681)	$437

Our cash flows used for financing activities decreased $244 million in 2003 from $681 million during the prior year. This decrease was due to additional proceeds from the issuance of common stock and the reduction of our common stock dividend in 2003.

In 2002 we used $681 million for financing activities compared to $437 million provided by the same activities in 2001. The increase in cash used pertained primarily to the debt retirements that occurred in 2002.

The following financing activities occurred during 2003 and 2002:

Common Stock and Equity Units:

- In March 2003, we issued 56 million shares of common stock at $20.95 per share through an equity offering and received net proceeds of $1.1 billion (net of issuance costs of $36 million). We used the proceeds to pay down both short-term and long-term debt with the balance being held in cash.

- In June 2002, we issued 16 million shares of common stock at $40.90 per share and 6.9 million equity units at $50 per unit and received combined net proceeds of $979 million. We used the proceeds to pay down short-term debt and establish a cash liquidity reserve fund.

Debt:

- We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a utility money pool which funds the utility subsidiaries and a non-utility money pool which funds the majority of the non-utility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. As of December 31, 2003, we had credit facilities totaling $2.9 billion to support our commercial paper program. At December 31, 2003, we had $282 million outstanding in short-term borrowings supported by these credit facilities. In addition, JMG has commercial paper outstanding in the amount of $26 million. This commercial paper is specifically associated with the Gavin scrubber lease. This commercial paper does not reduce available liquidity.

- In February 2003, we issued over $2 billion of senior notes through our Ohio and Texas subsidiaries. The proceeds were used to repay the bank facility that was due to mature in April 2003, retire short-term debt and for other general corporate purposes. During the remainder of the year, our subsidiaries issued an additional $2.3 billion in senior notes and refinanced approximately $465 million in pollution control revenue bonds. The proceeds of these issuances were used to term-out short-term debt, fund long-term debt maturities and fund optional redemptions.

- In March 2003, AEP issued a $500 million senior unsecured note. The proceeds of this issuance were used to pay-down $225 million of the Steelhead financing and to prefund a portion of the AEP Resources bond that matured in December 2003.

- In May 2003, a third party exercised its option to call our $250 million of 5.50% putable callable notes, issued in May 2001, for purchase and remarketing. On May 15, 2003, AEP issued $300 million of 5.25% senior notes due 2015, a portion of which was an exchange for the $250 million putable callable notes due in 2003 that were outstanding at that time.

- AEP Credit extended its sale of receivables agreement from its May 28, 2003 expiration to July 25, 2003, when the agreement was renewed for an additional 364 days. The sale of receivables agreement, which expires on July 23, 2004, provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

- In September 2003, we closed on a $200 million revolving loan and letter of credit facility. The facility is available for the issuance of letters of credit and for general corporate purposes. The facility will expire in September 2006.

Minority Interest and Off-balance Sheet Arrangements

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

Minority Interest in Finance Subsidiary

We formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis) in August 2001. SubOne is a wholly-owned consolidated subsidiary that was capitalized with the assets of Houston Pipe Line Company and Louisiana Intrastate Gas Company and $321.4 million of AEP Energy Services Gas Holding Company

(AEP Gas Holding is a subsidiary of AEP and the parent of SubOne) preferred stock, that was convertible into our common stock at market price on a dollar-for-dollar basis. Caddis was capitalized with $2 million cash and a subscription agreement that represents an unconditional obligation to fund $83 million from SubOne for a managing member interest and $750 million from Steelhead Investors LLC (Steelhead) for a non-controlling preferred member interest. SubOne is the managing member of Caddis. As a result SubOne and all of its subsidiaries, including Caddis, HPL and LIG, are included in our Consolidated financial statements.

Steelhead is an unconsolidated special purpose entity and had an original capital structure of $750 million (currently approximately $525 million) of which 3% is equity from investors with no relationship to us or any of our subsidiaries and 97% is debt from a syndicate of banks. The $525 million invested in Caddis by Steelhead was loaned to SubOne. The loan to SubOne is due August 2006. Net proceeds from the planned sale of LIG will be used to reduce the outstanding balance of the loan from Caddis.

On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis, which included amounts previously reported as Minority Interest in Finance Subsidiary ($759 million at December 31, 2002 and $533 million at June 30, 2003). As a result, a $527 million note payable to Caddis is part of our Long-Term Debt at December 31, 2003. Application of FIN 46 is prospective and we, therefore, did not change the presentation of Minority Interest in Finance Subsidiary in periods prior to July 1, 2003.

On May 9, 2003, we reduced the outstanding balance of our note payable to Caddis by $225 million. Caddis used these proceeds to reduce the preferred interest in Caddis that was held by Steelhead. This payment eliminated the convertible preferred stock of AEP Gas Holding which under certain conditions had been convertible to AEP stock.

The credit agreement between Caddis and SubOne contains covenants that restrict certain incremental liens and indebtedness, asset sales, investments, acquisitions, and distributions. The credit agreement also contains covenants that impose minimum financial ratios. Non-performance of these covenants may result in an event of default under the credit agreement. Through December 31, 2003, SubOne has complied with the covenants contained in the credit agreement. In addition, the acceleration of our outstanding debt in excess of $50 million would be an event of default under the credit agreement.

SubOne has deposited $422 million in a cash reserve fund in order to comply with certain covenants in the credit agreement. Pursuant to the terms of the credit agreement, SubOne subsequently loaned these funds to affiliates, and we guaranteed the repayment obligations of these affiliates. These loans must be repaid in the event our credit ratings fall below investment grade.

Steelhead has certain rights as a preferred member in Caddis. Upon the occurrence of certain events, including a default in the payment of the preferred return, Steelhead's rights include forcing a liquidation of Caddis and acting as the liquidator. Liquidation of Caddis could negatively impact our liquidity.

AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. We continue to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivables less an allowance for anticipated uncollectible accounts.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each respective company are $1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Railcars

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

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

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over time from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2003, the maximum potential loss was approximately $31.5 million ($20.5 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year to an unaffiliated company under an operating lease. The sublessee may renew the lease for up to four additional one-year terms. AEP has other railcar lease arrangements that do not utilize this type of financing structure.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in millions)				
Contractual Cash Obligations	Less Than 1 year	2-3 years	4–5 years	After 5 years	Total
Long-term Debt	$1,779	$3,460	$1,711	$7,151	$14,101
Short-term Debt	326	-	-	-	326
Preferred Stock Subject to Mandatory Redemption	-	-	21	55	76
Capital Lease Obligations	63	77	49	31	220
Unconditional Purchase Obligations (a)	1,720	2,132	1,101	1,785	6,738
Noncancellable Operating Leases	291	492	441	2,331	3,555
Total	$4,179	$6,161	$3,323	$11,353	$25,016

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.

Some of the transactions, described under "Minority Interest and Off-Balance Sheet Arrangements" above, include contractual cash obligations reported in the above table. The lease of Rockport Unit 2 and Railcars are reported in Noncancellable Operating Leases. The Minority Interest in Finance Subsidiary is reported in Long-term Debt.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds, and other commitments. Our commitments outstanding at December 31, 2003 under these agreements are summarized in the table below:

	Amount of Commitment Expiration Per Period (in millions)				
Other Commercial Commitments	Less Than 1 year	2-3 years	4–5 years	After 5 years	Total
Standby Letters of Credit (a)	$175	$43	$-	$9	$227
Guarantees of the Performance of Outside Parties (b)	-	18	1	134	153
Guarantees of our Performance	1,083	107	-	8	1,198
Transmission Facilities for Third Parties (c)	99	110	54	-	263
Other Commercial Commitments (d)	14	14	-	-	28
Total Commercial Commitments	$1,371	$292	$55	$151	$1,869

(a) We have issued standby letters of credit to third parties. These letters of credit cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in the ordinary course of business. The maximum future payments of these letters of credit are $227 million with maturities ranging from January 2004 to January 2011. As the parent of all of these subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

(b) These amounts are the balances drawn, not the maximum guarantee disclosed in Note 8.

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

(d) OPCo has entered into a 30-year power purchase agreement for electricity produced by an unaffiliated entity's three-unit natural gas fired plant. The plant was completed in 2002 and the agreement will terminate in 2032. Under the terms of the agreement, OPCo has the option to run the plant until December 31, 2005, taking 100% of the power generated and making monthly capacity payments. The capacity payments are fixed through December 2005 at $1.2 million per month. For the remainder of the 30-year contract term, OPCo will pay the variable costs to generate the electricity it purchases which could be up to 20% of the plant's capacity.

Expenditures for domestic electric utility construction are estimated to be $5.8 billion for the next three years. Approximately 80% of those construction expenditures is expected to be financed by internally generated funds.

Other

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. The Facility is a "qualifying cogeneration facility" for purposes of PURPA. Construction of the Facility was begun by Katco Funding, Limited Partnership (Katco), an unrelated unconsolidated special purpose entity. Katco assigned its interest in the Facility to Juniper in June 2003.

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

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation (COD). In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded $496 million of construction work in progress (CWIP) and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since the debt obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the above table of future minimum lease payments.

We are the construction agent for Juniper. We expect to achieve COD in the spring of 2004, at which time the obligation to make payments under the lease agreement will begin to accrue and we will sublease the Facility to The Dow Chemical Company (Dow). If COD does not occur on or before March 14, 2004, Juniper has the right to terminate the project. In the event the project is terminated before COD, we have the option to either purchase the Facility for 100% of Juniper's acquisition cost (in general, the outstanding debt and equity associated with the Facility) or terminate the project and make a payment to Juniper for 89.9% of project costs (in general, the acquisition cost less certain financing costs).

The initial term of the lease agreement between Juniper and AEP commences on COD and continues for five years. The lease contains extension options, and if all extension options are exercised, the total term of the lease will be 30 years. AEP's lease payments to Juniper during the initial term and each extended term are sufficient for Juniper to make required debt payments under Juniper's debt financing associated with the Facility and provide a return on equity to the investors in Juniper. We have the right to purchase the Facility for the acquisition cost during the last month of the initial term or on any monthly rent payment date during any extended term. In addition, we may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if we have arranged a sale of the Facility to an unaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow. If the lease were renewed for up to a 30-year lease term, we may further renew the lease at fair market value subject to Juniper's approval, purchase the Facility at its acquisition cost, or sell the Facility, on behalf of Juniper, to an independent third party. If the Facility is sold and the proceeds from the sale are insufficient to pay all of Juniper's acquisition costs, we may be required to make a payment (not to exceed $396 million) to Juniper of the excess of Juniper's acquisition costs over the proceeds from the sale, provided that we would not be required to make any payment if we have made the additional rental prepayment described below. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report the debt related to the Facility on our balance sheet, the fair value of the liability for our guarantee (the $396 million payment discussed above) is not separately reported.

At December 31, 2003, Juniper's acquisition costs for the Facility totaled $496 million, and total costs for the completed Facility are currently expected to be approximately $525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR. Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately $18 million represent future minimum payments for interest on Juniper's financing structure during the initial term calculated using the indexed LIBOR rate (1.15% at December 31, 2003). An additional rental prepayment (up to $396 million) may be due on June 30, 2004 unless Juniper has refinanced its present debt financing on a long-term basis. Juniper is currently planning to refinance by June 30, 2004. The Facility is collateral for the debt obligation of Juniper. At December 31, 2003, we reflected $396 million of the $496 million recorded obligation as long-term debt due within one year. Our maximum required cash payment as a result of our financing transaction with Juniper is $396 million as well as interest payments during the lease term. Due to the treatment of the Facility as a financing of an owned asset, the recorded liability of $496 million is greater than our maximum possible cash payment obligation to Juniper.

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as non-conforming.

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

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004, and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately $17.5 million. TEM may also claim that we are not entitled to receive any termination value for the PPA.

The current litigation between TEM and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power freed up by the TEM contract termination, triggered us to review the project for possible impairment of its reported values. We determined that the value of the Facility was impaired and recorded a $258 million pre-tax impairment in December 2003 on the CWIP.

SIGNIFICANT FACTORS

Possible Divestitures

We are firmly committed to continually evaluating the need to reallocate resources to areas that effectively match our investments with our business strategy, providing the greatest potential for financial returns. We are committed to disposing of investments that no longer meet these goals.

We are seeking to divest significant components of our non-regulated assets, including certain domestic and international unregulated generation, part of our gas pipeline and storage business, a coal business, independent power producers (IPPs) and a communications business. In June 2003, we began actively seeking buyers for 4,497 megawatts of unregulated generating capacity in Texas. The value received from this disposition will also be used to calculate our stranded costs in Texas (see Note 6). We are currently evaluating bids received during the fourth quarter of 2003 and are in negotiations to sell these assets.

During the second quarter of 2003, we also hired an advisor to evaluate our coal business, which has resulted in the receipt of non-binding bids. We are currently negotiating the anticipated sale of certain assets from this business. In the fourth quarter of 2003, in connection with the evaluation of this business, we recorded a $66.6 million pre-tax charge related to asset impairments, remediation accruals and other exit costs (see Note 10).

During the third quarter of 2003, management hired advisors to review business options regarding various investment components of our Gas Operations. We distributed an initial offering memorandum and request for proposal on the sale of our Louisiana Intrastate Gas and Jefferson Island Storage Facility operations during the fourth quarter of 2003. We are currently evaluating the proposals that we received. We are evaluating the merits of retaining our interest in Houston Pipe Line, which is part of Gas Operations. In connection with our review of the Gas Operations, we recorded $133.9 million in pre-tax charges related to LIG and $315 million in pre-tax charges related to HPL (see Note 10). We signed a sale agreement for the pipeline portion of LIG in the first quarter of 2004 and we expect the sale to close shortly with an immaterial impact on 2004 results of operations.

During the third quarter of 2003, we initiated an effort to sell four domestic IPP investments. Based on studies using current market assumptions, we believe that two of the facilities had declines in fair value that are other than temporary in nature. As a consequence, we recorded an impairment of $70 million pre-tax ($45.5 million net of tax) in the third quarter of 2003 (see Note 10). During the fourth quarter of 2003, we distributed an information memorandum related to the possible sale of our interest in these IPPs. We have received and are reviewing final bids and anticipate a sale of the four domestic IPP investments in 2004.

During the fourth quarter of 2003, we engaged an advisor for the disposition of our U.K. business and are planning to dispose of these assets in 2004. In connection with the evaluation of this business, we recorded a pre-tax charge of $577.4 million during the fourth quarter of 2003 based on indications of value received from potential buyers (see Note 10).

Management continues to have periodic discussions with various parties on business alternatives for certain of our other non-core investments.

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

Corporate Separation

In Texas, we are in the process of divesting our TCC generating assets in accordance with provisions of the Texas Legislation concerning stranded cost recovery (see Note 6). In order to sell these assets, we anticipate retiring TCC's first mortgage bonds by making open market purchases or defeasing the bonds. Once such generating assets are sold, which we expect to be finalized in 2004, we will effectively accomplish the structural separation requirements of the Texas Legislation for those assets.

In Ohio, the PUCO has encouraged utilities to file rate stabilization plans to provide rate certainty and stability for customers who do not choose alternative suppliers, for the period of January 1, 2006 through December 31, 2008, which is after the expiration of the current market development period. On February 9, 2004, CSPCo and OPCo filed such a rate stabilization plan with the PUCO. The plan, in part, provides that both CSPCo and OPCo will remain functionally separated. Approval of the rate stabilization plan is currently pending before the PUCO.

Unless otherwise directed by the PUCO in an order on the rate stabilization plan, CSPCo and OPCo will remain functionally separated through at least the end of the rate stabilization plan period, December 31, 2008, and therefore, are not planning to legally separate, or to change the affiliate pooling agreement for the AEP East companies, in the foreseeable future.

Management continues to evaluate the most appropriate approach for complying with the Texas Legislation's structural separation requirements for TNC, including appropriate regulatory approvals to implement its structural separation.

RTO Formation

The FERC's AEP-CSW merger approval and many of the settlement agreements with the state regulatory commissions to approve the AEP-CSW merger required the transfer of functional control of our subsidiaries' transmission systems to RTOs. Further, legislation in some of our states requires RTO participation.

In May 2002, we announced an agreement with PJM to pursue terms for participation in its RTO for AEP East companies with final agreements to be negotiated. In July 2002, FERC issued an order accepting our decision to participate in PJM, subject to specified conditions. AEP and other parties continue to work on the resolution of those conditions.

In December 2002, our subsidiaries that operate in the states of Indiana, Kentucky, Ohio and Virginia filed for state regulatory commission approval of their plans to transfer functional control of their transmission assets to PJM. Proceedings in Ohio remain pending.

In February 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed a cost/benefit study with the Virginia SCC covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately $13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In April 2003, FERC approved our transfer of functional control of the AEP East companies' transmission system to PJM. FERC also accepted our proposed rates for joining PJM, but set a number of rate issues for resolution through settlement proceedings or FERC hearings. Settlement discussions continue on certain rate matters.

On September 29 and 30, 2003, the FERC held a public inquiry regarding RTO formation, including delays in AEP's participation in PJM. In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger commitment to join an RTO by fully integrating into PJM (transmission and markets) by October 1, 2004. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the states' provisions meet either of the two exceptions under PURPA. The FERC directed the ALJ to issue his initial decision by March 15, 2004.

If AEP East companies do not obtain regulatory approval to join PJM, we are committed to reimburse PJM for certain project implementation costs (presently estimated at $24 million for AEP's share of the entire PJM integration project). AEP also has $28 million, at December 31, 2003, of deferred RTO formation/integration costs for which we plan to seek recovery in the future. See Note 4 for further discussion.

AEP West companies are members of ERCOT or SPP. In 2002, FERC conditionally accepted filings related to a proposed consolidation of MISO and SPP. State public utility commissions also regulate our SPP companies. The Louisiana and Arkansas commissions filed responses to the FERC's RTO order indicating that additional analysis was required. Subsequently, the proposed SPP/MISO combination was terminated. On October 15, 2003, SPP filed a proposal at FERC for recognition as an RTO. In February 2004, FERC granted RTO status to the SPP, subject to fulfilling specified requirements. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

Management is unable to predict the outcome of these regulatory actions and proceedings or their impact on our transmission operations, results of operations and cash flows or the timing and operation of RTOs.

Pension Plans

We maintain qualified, defined benefit pension plans (Qualified Plans), which cover a substantial majority of non-union and certain union associates, and unfunded excess plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, we have entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits.

Our net periodic pension expense was an income item for all pension plans approximating $3 million and $44 million for the years ended December 31, 2003 and 2002, respectively, and is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Qualified Plans' assets. In 2002 and 2003, the long-term return was assumed to be 9.00%, and for 2004, the long-term rate of return was lowered to 8.75%. In developing the expected long-term rate of return assumption, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. We also considered historical returns of the investment markets as well as our 10-year average return, for the period ended December 2003, of approximately 10.0%. We anticipate that the investment managers we employ for the pension fund will continue to generate long-term returns of at least 8.75%.

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

	2003 Actual Asset Allocation	2004 Target Asset Allocation	Assumed/Expected Long-term Rate of Return
		(in percentage)	
Equity	71	70	10.5
Fixed Income	27	28	5
Cash and Cash Equivalents	2	2	2
Total	100	100	
Overall Expected Return (weighted average)			8.75

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. We believe that 8.75% is a reasonable long-term rate of return on the Qualified Plans' assets despite the recent market volatility in which the Qualified Plans' assets had a loss of 11.2% for the twelve months ended December 31, 2002, and a gain of 23.8% for the twelve months ended December 31, 2003. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them as necessary.

We base cur determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2003, we had cumulative losses of approximately $325 million which remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The discount rate that we utilize for determining future pension obligations is based on a review of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis has decreased from 6.75% at December 31, 2002, to 6.25% at December 31, 2003. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Qualified Plans' assets of 8.75%, a discount rate of 6.25% and various other assumptions, we estimate that the pension expense for all pension plans will approximate $41 million, $78 million and $103 million in 2004, 2005 and 2006, respectively. Future actual pension cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the pension plans.

Lowering the expected long-term rate of return on the Qualified Plans' assets by 0.5% (from 9.0% to 8.5%) would have increased pension cost for 2003 by approximately $18 million (income of $3 million would have become $15 million in pension expense). Lowering the discount rate by 0.5% would have reduced pension income for 2003 by approximately $0.5 million.

The value of the Qualified Plans' assets has increased from $2.795 billion at December 31, 2002 to $3.180 billion at December 31, 2003. The Qualified Plans paid out $292 million in benefits to plan participants during 2003 (the nonqualified plans paid out $7 million in benefits). Our plans remain in an underfunded position (plan assets are less than projected benefit obligations) of $508 million at December 31, 2003. Due to the pension plans currently being underfunded, we recorded a charge to Other Comprehensive Income (OCI) of $585 million in 2002, and recorded a Deferred Income Tax Asset of $315 million, offset by a Minimum Pension Liability of $662 million and a reduction to prepaid costs and adjustment for unrecognized costs of $238 million. In 2003, the income recorded in OCI was $154 million, and the reduction in the Deferred Income Tax Asset was $76 million, offset by a reduction in Minimum Pension Liability of $234 million and a reduction to adjustment for unrecognized costs of $4 million. The charge to OCI does not affect earnings or cash flow. Due to the current underfunded status of the Qualified Plans, we expect to make cash contributions to the pension plans of approximately $41 million in 2004.

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

<u>**Nuclear Plant Outages**</u>

In April 2003, engineers at STP, during inspections conducted regularly as part of refueling outages, found wall cracks in two bottom mounted instrument guide tubes of STP Unit 1. These tubes were repaired and the unit returned to service in August 2003. Our share of the cost of repair for this outage was approximately $6 million. We had commitments to provide power to customers during the outage. Therefore, we were subject to fluctuations in the market prices of electricity and purchased replacement energy.

In April 2003, both units of Cook Plant were taken offline due to an influx of fish in the plant's cooling water system which caused a reduction in cooling water to essential plant equipment. After repair of damage caused by the fish intrusion, Cook Plant Unit 1 returned to service in May and Unit 2 returned to service in June following completion of a scheduled refueling outage.

Litigation

Federal EPA Complaint and Notice of Violation

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

Enron Bankruptcy

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In connection with the 2001 acquisition of HPL, we acquired exclusive rights to use and operate the underground Bammel gas storage facility pursuant to an agreement with BAM Lease Company, a now-bankrupt subsidiary of Enron. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years and includes the use of the Bammel storage facility and the appurtenant pipelines. We have engaged in discussions with Enron concerning the possible purchase of the Bammel storage facility and related assets, the possible resolution of outstanding issues between AEP and Enron relating to our acquisition of HPL and the possible resolution of outstanding energy trading issues. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. We are unable to predict whether these discussions will lead to an agreement on these subjects. In January 2004, AEP and its subsidiaries filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron does not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In February 2004 Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. Management is unable to predict the outcome of these proceedings or the impact on results of operations, cash flows or financial condition.

We also entered into an agreement with BAM Lease Company which grants HPL the exclusive right to use approximately 65 billion cubic feet of cushion gas required for the normal operation of the Bammel gas storage facility. The Bammel Gas Trust (owned by Enron and Bank of America (BOA)) purports to have a lien on 55 billion cubic feet of this cushion gas. These banks claim to have certain rights to the cushion gas in certain events of default. In connection with our acquisition of HPL, the banks and Enron entered into an agreement granting HPL's exclusive use of 65 billion cubic feet of cushion gas. Enron and the banks released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, HPL was informed by the banks of a purported default by Enron under the terms of the financing arrangement. In July 2002, the banks filed a lawsuit against HPL in the state court of Texas seeking a declaratory judgment that they have a valid and enforceable security interest in gas purportedly in the Bammel storage facility which would permit them to cause the withdrawal of up to 55 billion cubic feet of gas from the storage facility. In September 2002, HPL filed a general denial and certain counterclaims against the banks including that Enron was a necessary and indispensable party to the Texas state court proceeding initiated by BOA. HPL also filed a motion to dismiss, which was denied. In December 2003, the Texas state court granted partial summary judgment in favor of the banks. HPL appealed this decision. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows and financial condition.

In October 2003, AEP Energy Services Gas Holding Company filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. On January 8, 2004, this lawsuit was amended and seeks damages for BOA's breach of contract, negligent misrepresentation and fraud in connection with transactions surrounding our acquisition of HPL from Enron including entering into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangements with BOA and Enron. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. We will assert our right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

During 2002 and 2001, we expensed a total of $53 million ($34 million net of tax) for our estimated loss from the Enron bankruptcy. The amount expensed was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and the Bammel storage facility lease agreement and cushion gas agreement. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals and claimed that we owed approximately $34 million. In April 2003, we filed a lawsuit against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately $68 million. We are claiming that BOM owes us at least $45 million. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Arbitration of Williams Claim

In 2002, we filed a demand for arbitration with the American Arbitration Association to initiate formal arbitration proceedings in a dispute with the Williams Companies (Williams). The proceeding results from Williams' repudiation of its obligations to provide physical power deliveries to AEP and Williams' failure to provide the monetary security required for natural gas deliveries. AEP and Williams settled the dispute with AEP paying $90 million to Williams in June 2003. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the resolution of this matter had an immaterial impact on results of operations and financial condition. See Note 7 for further discussion.

Arbitration of PG&E Energy Trading, LLC Claim

In January 2003, PG&E Energy Trading, LLC (PGET) claimed approximately $22 million was owed by AEP in connection with the termination and liquidation of all trading deals. In February 2003, PGET initiated arbitration proceedings. In July 2003, AEP and PGET agreed to a settlement with AEP paying approximately $11 million to PGET. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the settlement payment did not have a material impact on results of operations, cash flows or financial condition.

Energy Market Investigations

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

In March 2003, we received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, we had received an informal data request from the SEC seeking that we voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. We responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, we recorded a provision in 2003 and the action is not expected to have a material effect on results of operations.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. We are responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

Shareholders' Litigation

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

California Lawsuit

In 2002, the Lieutenant Governor of California filed a lawsuit in California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP has been dismissed from the case. See Note 7 for further discussion.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Shortly thereafter, a similar action was filed in the same court against eighteen companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. These cases are in the initial pleading stage. Management believes that the cases are without merit and intends to vigorously defend against them.

TEM Litigation

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

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP. (TCE), a Texas REP, filed a lawsuit against us and four AEP subsidiaries, certain unaffiliated energy companies and ERCOT alleging violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Management believes that the claims against us are without merit. We intend to vigorously defend against the claims. See Note 7 for further discussion.

COLI Litigation

A decision by the U.S. District Court for the Southern District of Ohio in February 2001 that denied AEP's deduction of interest claimed on AEP's consolidated federal income tax returns related to a COLI program resulted in a $319 million reduction in AEP's Net Income for 2000. We filed an appeal of the U.S. District Court's decision with the U.S. Court of Appeals for the 6th Circuit. In April 2003, the Appeals Court ruled against AEP. The U.S. Supreme Court has declined to hear this issue.

Snohomish Settlement

In February 2003, AEP and the Public Utility District No. 1 of Snohomish County, Washington (Snohomish) agreed to terminate their long-term contract signed in January 2001. Snohomish also agreed to withdraw its complaint before the FERC regarding this contract and paid $59 million to us. The settlement amount was less than the amount receivable that, in the ordinary course of business, we recorded using MTM accounting. As a result, we incurred a $10 million pre-tax loss.

Other Litigation

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

Potential Uninsured Losses

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

<u>Environmental Matters</u>

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

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

In addition to achieving full compliance with all applicable legal requirements, we strive to go beyond compliance in an effort to be good environmental stewards. For example, we invest in research, through groups like the Electric

Power Research Institute, to develop, implement and demonstrate new emission control technologies. We plan to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices. We have a proven record of efficiently producing and delivering electricity and gas while minimizing the impact on the environment. We invested over $2 billion, from 1990 through 2003, to equip many of our facilities with pollution control technologies. We will continue to make investments to improve the air emissions from our generating stations because this is the most cost-effective generation source for our customers electricity needs.

The Current Air Quality Regulatory Framework

The Clean Air Act (CAA) is the legislation that establishes the federal regulatory authority and oversight for emissions from our fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

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

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

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

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

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which we operate that were subject to the NOx Rule have submitted the required SIP revisions. In response, the Federal EPA issued the NOx Rule and the Section 126 Rule, which are discussed below.

The compliance date for the NOx Rule is May 31, 2004. In 2000, the Federal EPA also adopted a revised Section 126 Rule which granted petitions filed by four northeastern states. The revised Section 126 Rule imposes emissions reduction requirements comparable to the NOx Rule also beginning May 31, 2004, for most of our coal-fired generating units.

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

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

AEP's electric utility units are currently subject to SIP requirements that control SO_2 and particulate matter emissions in all states, and that control NOx emissions in certain states. Our generating plants comply with applicable SIP limits for SO_2, NOx and particulate matter.

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

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

Different NSR requirements apply in attainment and non-attainment areas.

In attainment areas:

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

In non-attainment areas,

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

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

Title IV of the CAA (Acid Rain)

The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO_2 emitted from electric utility units by approximately 50 percent from 1980 levels. This program also established a nationwide cap on utility SO_2 emissions of 8.9 million tons per year. The Federal EPA administers its SO_2 program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each utility unit must surrender one allowance for each ton of SO_2 that it emits. Emission sources that install controls and no longer need all of their allowances can bank those allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NOx emissions through the use of available combustion controls. Units must meet NOx emission rates standards which are specific to that unit or units may participate in an annual averaging program for utility units that are under common control.

Future Reduction Requirements for SO_2, NOx, and Mercury

In 1997, the Federal EPA adopted new, more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter and ground-level ozone non-attainment areas. The Federal EPA has identified SO_2 and NOx emissions as precursors to the formation of fine particulate matter. NOx emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NOx and SO_2 from our generating units are highly probable. In addition, the Federal EPA has proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation, known as the Clear Skies Act, was introduced in Congress and is supported by the Bush Administration. This legislation would regulate NOx, SO_2, and mercury emissions from electric generating plants. We support enactment of this comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. We believe the Bush Administration's Clear Skies Act would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. Although the prospects for enactment of the Clear Skies Act are low, there are alternative regulatory approaches which will likely require us to substantially reduce SO_2, NOx and mercury emissions over the next ten years.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO_2, NOx and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed an interstate air quality rule for reducing SO_2 and NOx emissions across the eastern half of the United States (29 states and the District of Columbia) to address attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The interstate air quality rule would require affected states to include, in their SIPs, a program to reduce NOx and SO_2 emissions from coal-fired electric utility units. SO_2 and NOx emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO_2 emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NOx emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO_2 and NOx trading programs have not yet been proposed.

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

The Federal EPA recommends, and we support, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO_2 and NOx reduction requirements imposed on the same sources under the proposed interstate air quality rule. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, that can be used to comply with the more stringent SO_2 and NOx requirements, have also proven highly effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018.

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

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that we will invest in additional conventional pollution control technology on a major portion of our fleet of coal-fired power plants. Finalization of new requirements for further SO_2, NOx and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control.

Estimated Air Quality Environmental Investments

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

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

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

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

All of the costs discussed below are incremental to our current investment base and operating cost structure. These expenditures for pollution control technologies, replacement generation and associated operating costs are recoverable from customers through regulated rates (in regulated jurisdictions) and should be recoverable through market prices (in deregulated jurisdictions). If not, those costs could adversely affect future results of operations and cash flows, and possibly financial condition.

Estimated Investments for NOx Compliance

We estimate that we will make future investments of approximately $600 million to comply with the Federal EPA's NOx Rule, the Texas Commission on Environmental Quality Rule and other final Federal EPA NOx-related requirements. Approximately $500 million of these investments are reflected in our estimated construction expenditures for 2004 – 2006. As of December 31, 2003, we have invested approximately $1.1 billion to comply with various NOx requirements.

Estimated Investments for SO2 Compliance

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

- Receive in the annual allowance allocation by the Federal EPA,
- Obtain through participation in the annual allowance auction,
- Purchase in the allowance market, and
- Obtained as bonus allowances for installing controls early.

Decreasing SO_2 allowance allocations, a diminishing SO_2 allowance bank, and increasing allowance prices in the market will require us to install additional controls on certain of our generating units. We plan to install 3,500 MW of additional scrubbers over the next 4 years to comply with our Title IV SO_2 obligations. In total we estimate these additional capital costs to be approximately $1.2 billion. Of this total, we estimate that $900 million will be expended during 2004-2006 and this amount is included in our total estimated construction expenditures for 2004 – 2006.

Estimated Investments to Comply with Future Reduction Requirements

Our planning assumptions for the levels and timing of emissions reductions parallel the reduction levels and implementation time periods stated in the proposed rules issued by the Federal EPA in January 2004. We have also assumed that the Federal EPA will implement a mercury trading option and will design its proposed cap and trade mechanism for SO_2, NOx and mercury emissions in a manner similar to existing cap and trade programs. Based on these assumptions, compliance would require additional capital investment of approximately $1.7 billion by 2010, the end of the first phase for each proposed rule. We also estimate that we would incur increases in variable operation and maintenance expenses of $150 million for the periods by 2010, due to the costs associated with the maintenance of additional control systems, disposal of scrubber by-products and the purchase of reagents. We estimate that we will invest $200 million of this amount through 2006, and this amount is included in our total estimated construction expenditures for 2004 – 2006.

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

Beyond 2010, we expect to incur additional costs for pollution control technology retrofits and associated operation and maintenance of the equipment. We cannot estimate these additional costs because of the uncertainties associated with the final control requirements and our associated compliance strategy, but these capital and operating costs will be significant.

New Source Review Litigation

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

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

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

Superfund and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and non-hazardous materials. We are currently incurring costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized the Federal EPA to administer the clean-up programs. As of year-end 2003, subsidiaries of AEP are named by the Federal EPA as a PRP for five sites. There are six additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at six sites under state law. Liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

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

Global Climate Change

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO_2, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not submitted to the Senate for its advice and consent by President Clinton. In March 2001, President Bush announced his opposition to the treaty. Ratification of the treaty by a majority of the countries' legislative bodies is required for it to be enforceable. Enforceability of the protocol is now contingent on ratification by Russia, which has expressed concerns about doing so.

On August 28, 2003, the Federal EPA issued a decision in response to a petition for rulemaking seeking reductions of CO_2 and other greenhouse gas emissions from mobile sources. The Federal EPA denied the petition and issued a memorandum stating that it does not have the authority under the Clean Air Act to regulate CO_2 or other greenhouse gas emissions that may affect global warming trends. The Circuit Court of Appeals for the District of Columbia is reviewing these actions.

We do not support the Kyoto Protocol but have been working with the Bush Administration on a voluntary program aimed at meeting the President's goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, we have been a leader in pursuing voluntary actions to control greenhouse gas emissions. We expanded our commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program, under which we are obligated to reduce or offset 18 million tons of CO_2 emissions during 2003-2006.

We acquired 4,000 MW of coal-fired generation in the United Kingdom in December 2001. These assets may have future CO_2 emission control obligations beginning in 2005. We plan to dispose of our investment in this generation during 2004.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law I&M and TCC participate in the DOE's SNF disposal program which is described in Note 7. Since 1983 I&M has collected $316 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. We deposited $117 million of these funds in external trust funds to provide for the future disposal of SNF and remitted $199 million to the DOE. TCC has collected and remitted to the DOE, $56 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of TCC and the other STP owners, along with a number of 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 proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other 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. On January 17, 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continues on the issue of damages owed to I&M by the DOE with a trial scheduled in March 2004. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2003 estimate the cost to decommission the Cook Plant ranges from $821 million to $1.08 billion in 2003 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2003, the total decommissioning trust fund balance for Cook Plant was $720 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate TCC'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, 2003, the total decommissioning trust fund for TCC's share of STP was $125 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. I&M and TCC will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, our future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Clean Water Act Regulation

On February 16, 2004, the Federal EPA signed a rule pursuant to the Clean Water Act that will require all large existing power plants to meet certain performance standards to reduce the mortality of juvenile and adult fish or other larger organisms pinned against a plant's cooling water intake screens. A subset of these plants that are located on sensitive water bodies will be required to meet additional performance standards for reducing the number of smaller organisms passing through the water screens and the cooling system. Sensitive water bodies are defined as oceans, estuaries, the Great Lakes, and small rivers with large plants. These rules will result in additional capital and operation and maintenance expenses to ensure compliance.

Other Environmental Concerns

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

Critical Accounting Policies

In the ordinary course of business, we use a number of estimates and assumptions relating to the reporting of results of operations and financial condition in the preparation of our financial statements in conformity with accounting principles generally accepted in the United States of America, including amounts related to legal matters and contingencies. Actual results can differ significantly from those estimates under different assumptions and conditions.

We believe that the following discussion addresses the most critical accounting policies, which are those that are most important to the portrayal of the financial condition and results and require management's most difficult, subjective and complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain.

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with its passage to customers through regulated revenues in the same accounting period. We also record regulatory liabilities for refunds, or probable refunds, to customers that have not yet been made.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write-off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

We recognize revenues on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. That is, we recognize and record revenues when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Domestic Gas Pipeline and Storage Activities

We recognize revenues from domestic gas pipeline and storage services when gas is delivered to contractual meter points or when services are provided, with the exception of certain physical forward gas purchase and sale contracts that are derivatives and are required to be accounted for using mark-to-market accounting (Resale Gas Contracts).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in October 2002, these activities were focused on wholesale markets where we own assets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, we recorded wholesale marketing and risk management activities using the mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. We implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into prior to October 25, 2002, we implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change.

After January 1, 2003, we use mark-to-market accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and Rescission of EITF 98-10 in Note 2.

Accounting for Derivative Instruments

For derivative contracts that are not designated as hedges or normal purchase and sale transactions we recognize unrealized gains and losses prior to settlement based on changes in fair value during the period in our results of operations. When we settle mark-to-market derivative contracts and realize gains and losses, we reverse previously recorded unrealized gains and losses from mark-to-market valuations.

We designate certain derivative instruments as hedges of forecasted transactions or future cash flows (cash flow hedges) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). We report changes in the fair value of these instruments on our balance sheet. We do not recognize changes in the fair value of the derivative instrument designated as a hedge in the current results of operations until earnings are impacted by the hedged item. We also recognize any changes in the fair value of the hedging instrument that are not offset by changes in the fair value of the hedged item immediately in earnings.

We measure the fair values of derivative instruments and hedge instruments accounted for using mark-to-market accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. There are inherent risks related to the underlying assumptions in models used to fair value open long-term derivative contracts. We have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

We recognize all derivative instruments at fair value in our Consolidated Balance Sheets as either "Risk Management Assets" or "Risk Management Liabilities." We do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in Revenues in the Consolidated Statement of Operations on a net basis, with the exception of physically settled Resale Gas Contracts for the purchase of natural gas. The unrealized and realized gains and losses on these Resale Gas Contracts are presented as Purchased Gas for Resale in the Consolidated Statement of Operations.

Long-Lived Assets

Long-lived assets are evaluated periodically for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. If the carrying amount is not recoverable, an impairment is recorded to the extent that the fair value of the asset is less than its book value.

Pension Benefits

We sponsor pension and other retirement plans in various forms covering all employees who meet eligibility requirements. We use several statistical and other factors which attempt to anticipate future events in calculating the expense and liability related to our plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates to estimate these factors. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded. See "Pension Plans" in Significant Factors section of Management's Financial Discussion and Analysis.

New Accounting Pronouncements

Effective July 1, 2003, we implemented FIN 46, "Consolidation of Variable Interest Entities." As a result of the implementation, we consolidated two entities, Sabine Mining Company ($77.8 million) and JMG ($469.6 million), which were previously off-balance sheet. These entities were consolidated with SWEPCo and OPCo, respectively. There is no change in net income due to the consolidations. In addition, we deconsolidated Cadis Partners, LLC and the trusts which hold mandatorily redeemable trust preferred securities which were previously reported as Minority Interest in Finance Subsidiary ($533 million) and Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries ($321 million), respectively. As a result of the deconsolidation these amounts are now included in Long-term Debt. In December 2003, the FASB issued FIN 46R which replaces FIN 46. The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

See Notes 1 and 2 to the consolidated financial statements for a discussion of significant accounting policies and additional impacts of new accounting pronouncements.

Other Matters

FERC Proposed Standard Market Design

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments that the FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until any potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

Seasonality

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

Non-Core Investments

Additional market deterioration associated with our non-core wholesale investments (all operations outside our traditional domestic regulated utility operations), including our U.K. operations, merchant generation facilities, and certain gas storage and pipeline assets, could have an adverse impact on future results of operations and cash flows. Further changes in external market conditions could lead to additional write-offs and further divestitures of our wholesale investments, including, but not limited to, the U.K. operations, merchant generation facilities, and our gas storage and pipeline operations. See Note 10 for additional information regarding assets and investments currently recorded as held for sale.

Investments Limitations

Our investment, including guarantees of debt, in certain types of activities is limited by PUHCA. SEC authorization under PUHCA limits us to issuing and selling securities in an amount up to 100% of our average quarterly consolidated retained earnings balance for investment in EWGs and FUCOs. At December 31, 2003, our investment in EWGs and FUCOs was $1.7 billion, including guarantees of debt, compared to our limit of $2.1 billion.

SEC Rule 58, under the general rules and regulations of the PUHCA, permits us to invest up to 15% of consolidated capitalization (such amount was $3.4 billion at December 31, 2003) in energy-related companies, including marketing and/or risk management activities in electricity, gas and other energy commodities. As of December 31, 2003 AEP has invested $2.8 billion in these energy-related companies.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

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

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

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

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

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2003

	Utility Operations	Investments Gas Operations	Investments UK Operations	Consolidated
		(in millions)		
Beginning Balance December 31, 2002	$360	$(155)	$ 45	$250
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(107)	175	(9)	59
Fair Value of New Contracts When Entered Into During the Period (b)	-	-	4	4
Net Option Premiums Paid/(Received) (c)	-	23	(14)	9
Change in Fair Value Due to Valuation Methodology Changes	-	1	-	1
Effect of EITF 98-10 Rescission (d)	(19)	1	(14)	(32)
Changes in Fair Value of Risk Management Contracts (e)	43	(40)	(134)	(131)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	9	-	-	9
UK Generation Hedges (g)	-	-	(124)	(124)
Total MTM Risk Management Contract Net Assets (Liabilities), excluding Cash Flow Hedges	$286	$5	$(246)	45
Net Cash Flow Hedge Contracts (h)				(134)
Net Risk Management Liabilities Held for Sale (i)				383
Ending Balance December 31, 2003				$294

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 and entered into prior to 2003.

(b) The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2003. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts entered into in 2003.

(d) See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect."

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

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

(g) "UK Generation Hedges" represent amounts previously classified as hedges of forecasted U.K. power sales relating to the fourth quarter of 2004 and beyond. Given the expected disposition of our U.K. generation in 2004, the forecasted sales are no longer probable of occurring. Therefore, these amounts have been reclassified from hedge accounting to mark-to-market accounting.

(h) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed in detail within the following pages.

(i) See Note 10 for discussion on Assets Held for Sale.

Detail on MTM Risk Management Contract Net Assets (Liabilities)
As of December 31, 2003

	Utility Operations	Investments Gas Operations	Investments UK Operations	Consolidated
		(in millions)		
Current Assets	$323	$417	$560	$1,300
Non Current Assets	279	215	274	768
Total Assets	$602	$632	$834	$ 2,068
Current Liabilities	$(216)	$(403)	$(646)	$(1,265)
Non Current Liabilities	(100)	(224)	(434)	(758)
Total Liabilities	$(316)	$(627)	$(1,080)	$(2,023)
Total Net Assets (Liabilities), excluding Cash Flow Hedges	$286	$5	$(246)	$45

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of December 31, 2003

	Risk Management Contracts*	Cash Flow Hedges	Assets Held for Sale	Consolidated
		(in millions)		
Current Assets	$1,300	$26	$(560)	$766
Non Current Assets	768	-	(274)	494
Total Assets	$2,068	$26	$(834)	$1,260
Current Liabilities	$(1,265)	$(148)	$782	$(631)
Non Current Liabilities	(758)	(12)	435	(335)
Total Liabilities	$(2,023)	$(160)	$1,217	$(966)
Total Net Assets (Liabilities)	$45	$(134)	$383	$294

* Excluding Cash Flow Hedges.

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

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

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

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
				(in millions)			
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$44	$(4)	$(1)	$-	$-	$-	$39
Prices Provided by Other External Sources – OTC Broker Quotes (a)	78	38	29	13	6	-	164
Prices Based on Models and Other Valuation Methods (b)	(15)	7	15	19	16	41	83
Total	$107	$41	$43	$32	$22	$41	$286
Investments - Gas Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$49	$14	$(1)	$-	$-	$-	$62
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(27)	-	-	-	-	-	(27)
Prices Based on Models and Other Valuation Methods (b)	(8)	(7)	(6)	(1)	(3)	(5)	(30)
Total	$14	$7	$(7)	$(1)	$(3)	$(5)	$5
Investments - UK Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$-	$-	$-	$-	$-	$-	$-
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(60)	(101)	(46)	-	-	-	(207)
Prices Based on Models and Other Valuation Methods (b)	(26)	(9)	(2)	(2)	-	-	(39)
Total	$(86)	$(110)	$(48)	$(2)	$-	$-	$(246)
Consolidated:							
Prices Actively Quoted – Exchange Traded Contracts	$93	$10	$(2)	$-	$-	$-	$101
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(9)	(63)	(17)	13	6	-	(70)
Prices Based on Models and Other Valuation Methods (b)	(49)	(9)	7	16	13	36	14
Total	$35	$(62)	$(12)	$29	$19	$36	$45

(a) Prices provided by other external sources – Reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) Modeled – In the absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled.
(c) For Utility Operations, there is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008. $17 million of this mark-to-market value is in 2009 and $16 million of this mark-to-market value is in 2010.
(d) Amounts exclude Cash Flow Hedges.

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

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of December 31, 2003

Domestic	Transaction Class	Market/Region	Tenor (in months)
Natural Gas	Futures	NYMEX Henry Hub	72
	Physical Forwards	Gulf Coast, Texas	12
	Swaps	Gas East – Northeast, Mid-continent Gulf Coast, Texas	15
	Swaps	Gas West – Rocky Mountains, West Coast	15
	Exchange Option Volitility	NYMEX/Henry Hub	12
Power	Futures	Power East – PJM	24
	Physical Forwards	Power East – Cinergy	60
	Physical Forwards	Power East – PJM	48
	Physical Forwards	Power East – NYPP	24
	Physical Forwards	Power East – NEPOOL	12
	Physical Forwards	Power East – ERCOT	24
	Physical Forwards	Power East – TVA	48
	Physical Forwards	Power East – Com Ed	24
	Physical Forwards	Power East – Entergy	48
	Physical Forwards	Power West – PV, NP15, SP15, MidC, Mead	60
	Peak Power Volatility (Options)	Cinergy	12
	Peak Power Volatility (Options)	PJM	12
Crude Oil	Swaps	West Texas Intermediate	36
Emissions	Credits	SO2	24
Coal	Physical Forwards	PRB,NYMEX,CSX	24
International			
Power	Forwards and Options	United Kingdom	24
Coal	Forward Purchases and Sales	United Kingdom	15
	Swaps	Europe	36
Freight	Swaps	Europe	24

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

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

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

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. International subsidiaries use currency swaps to hedge exchange rate fluctuations of debt denominated in foreign currencies. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place (However, given that under SFAS 133 only cash flow hedges are recorded in Accumulated Other Comprehensive Income (AOCI), the table does not provide an all-encompassing picture of our hedging activity). The table further indicates what portions of these hedges are expected to be reclassified into net income in the next 12 months. The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll off of hedges).

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

Cash Flow Hedges included in Accumulated Other Comprehensive Income (Loss) On the Balance Sheet as of December 31, 2003

	Accumulated Other Comprehensive Income (Loss) After Tax (a)	Portion Expected to be Reclassified to Earnings During the Next 12 Months (b)
	(in millions)	
Power and Gas	$(65)	$(58)
Foreign Currency	(20)	(20)
Interest Rate	(9)	(8)
Total	$(94)	$(86)

Total Accumulated Other Comprehensive Income (Loss) Activity Year Ended December 31, 2003

	Power and Gas	Foreign Currency	Interest Rate	Consolidated
		(in millions)		
Beginning Balance, December 31, 2002	$(3)	$(1)	$(12)	$(16)
Changes in Fair Value (c)	(64)	(19)	4	(79)
Reclassifications from AOCI to Net Income (d)	2	-	(1)	1
Ending Balance, December 31, 2003	$(65)	$(20)	$(9)	$(94)

(a) "Accumulated Other Comprehensive Income (Loss) After Tax" – Gains/losses are net of related income taxes that have not yet been included in the determination of net income; reported as a separate component of shareholders' equity on the balance sheet.

(b) "Portion Expected to be Reclassified to Earnings During the Next 12 Months" – Amount of gains or losses (realized or unrealized) from derivatives used as hedging instruments that have been deferred and are expected to be reclassified into net income during the next 12 months at the time the hedged transaction affects net income.

(c) "Changes in Fair Value" – Changes in the fair value of derivatives designated as cash flow hedges not yet reclassified into net income, pending the hedged items affecting net income. Amounts are reported net of related income taxes.

(d) "Reclassifications from AOCI to Net Income" – Gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. We believe that credit exposure with any one counterparty is not material to our financial condition at December 31, 2003. At December 31, 2003, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 16%, expressed in terms of net MTM assets and net receivables. The increase in non-investment grade credit quality was largely due to an increase in coal and freight exposures related to our U.K. investments. As of December 31, 2003, the following table approximates our counterparty credit quality and exposure based on netting across commodities and instruments:

Counterparty Credit Quality:	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties > 10%	Net Exposure of Counterparties > 10%
			(in millions)		
Investment Grade	$931	$29	$902	1	$135
Split Rating	47	-	47	1	40
Non-Investment Grade	276	136	140	2	71
No External Ratings:					
Internal Investment Grade	480	5	475	3	207
Internal Non-Investment Grade	185	48	137	2	51
Total	$1,919	$218	$1,701	9	$504

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged. This information is forward-looking and provided on a prospective basis through December 31, 2006. Please note that this table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged," represents the portion of megawatt hours of future generation/production for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of December 31, 2003

	2004	2005	2006
Estimated Plant Output Hedged	90%	92%	92%

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance - covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2003, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR year-to-date:

VaR Model

December 31, 2003 (in millions)				December 31, 2002 (in millions)			
End	High	Average	Low	End	High	Average	Low
$11	$19	$ 7	$4	$5	$24	$12	$4

The high VaR for 2003 occurred in late February 2003 during a period when natural gas and power prices experienced high levels and extreme volatility. Within a few days, the VaR returned to levels more representative of the average VaR for the year.

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

CCRO VaR Metrics

	December 31, 2003	Average for Year-to-Date 2003	High for Year-to-Date 2003	Low for Year-to-Date 2003
		(in millions)		
95% Confidence Level, Ten-Day Holding Period	$41	$27	$71	$16
99% Confidence Level, One-Day Holding Period	$17	$11	$30	$ 7

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $1.013 billion at December 31, 2003 and $527 million at December 31, 2002. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not materially affect our results of operations or consolidated financial position.

We are exposed to risk from changes in the market prices of coal and natural gas used to generate electricity where generation is no longer regulated or where existing fuel clauses are suspended or frozen. The protection afforded by fuel clause recovery mechanisms has either been eliminated by the implementation of customer choice in Ohio (effective January 1, 2001) and in the ERCOT area of Texas (effective January 1, 2002) or frozen by a settlement agreement in West Virginia. To the extent the fuel supply of the generating units in these states is not under fixed price long-term contracts we are subject to market price risk. We continue to be protected against market price changes by active fuel clauses in Oklahoma, Arkansas, Louisiana, Kentucky, Virginia and the SPP area of Texas. Fuel clauses are active again in Michigan and Texas, effective January 1, 2004 and March 1, 2004, respectively.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2003, 2002 and 2001
(in millions, except per-share amounts)

	2003	2002	2001
REVENUES			
Utility Operations	$10,871	$10,446	$10,546
Gas Operations	3,097	2,071	1,797
Other	577	791	410
TOTAL	14,545	13,308	12,753
EXPENSES			
Fuel for Electric Generation	3,053	2,577	3,225
Purchased Electricity for Resale	707	532	296
Purchased Gas for Resale	2,850	1,946	1,443
Maintenance and Other Operation	3,673	4,065	3,666
Asset Impairments and Other Related Charges	650	318	-
Depreciation and Amortization	1,299	1,348	1,233
Taxes Other Than Income Taxes	681	718	667
TOTAL	12,913	11,504	10,530
OPERATING INCOME	1,632	1,804	2,223
Other Income	387	461	371
INTEREST AND OTHER CHARGES			
Investment Value Losses	70	321	-
Other Expenses	227	323	225
Interest	814	775	833
Preferred Stock Dividend Requirements of Subsidiaries	9	11	10
Minority Interest in Finance Subsidiary	19	35	13
TOTAL	1,139	1,465	1,081
INCOME BEFORE INCOME TAXES	880	800	1,513
Income Taxes	358	315	553
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	522	485	960
DISCONTINUED OPERATIONS (Net of Tax)	(605)	(654)	41
EXTRAORDINARY LOSS (Net of Tax)	-	-	(48)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (Net of Tax)			
Goodwill and Other Intangible Assets	-	(350)	18
Accounting for Risk Management Contracts	(49)	-	-
Asset Retirement Obligations	242	-	-
NET INCOME (LOSS)	$110	$(519)	$971
AVERAGE NUMBER OF SHARES OUTSTANDING	385	332	322
EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect of Accounting Changes	$1.35	$1.46	$2.98
Discontinued Operations	(1.57)	(1.97)	0.13
Extraordinary Loss	-	-	(0.16)
Cumulative Effect of Accounting Changes	0.51	(1.06)	0.06
TOTAL EARNINGS PER SHARE (BASIC AND DILUTIVE)	$0.29	$(1.57)	$3.01
CASH DIVIDENDS PAID PER SHARE	$1.65	$2.40	$2.40

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in millions)	
CURRENT ASSETS		
Cash and Cash Equivalents	$1,182	$1,199
Accounts Receivable:		
Customers	1,155	1,553
Accrued Unbilled Revenues	596	551
Miscellaneous	83	93
Allowance for Uncollectible Accounts	(124)	(108)
Total Receivables	1,710	2,089
Fuel, Materials and Supplies	991	938
Risk Management Assets	766	850
Margin Deposits	119	110
Other	129	132
TOTAL	4,897	5,318
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	15,112	13,678
Transmission	6,130	5,866
Distribution	9,902	9,573
Other (including gas, coal mining and nuclear fuel)	3,584	3,656
Construction Work in Progress	1,305	1,354
TOTAL	36,033	34,127
Less: Accumulated Depreciation and Amortization	14,004	13,539
TOTAL-NET	22,029	20,588
OTHER NON-CURRENT ASSETS		
Regulatory Assets	3,548	2,688
Securitized Transition Assets	689	735
Spent Nuclear Fuel and Decommissioning Trusts	982	871
Investments in Power and Distribution Projects	212	283
Goodwill	78	241
Long-term Risk Management Assets	494	758
Other	733	792
TOTAL	6,736	6,368
Assets Held for Sale	3,082	3,601
Assets of Discontinued Operations	-	15
TOTAL ASSETS	$36,744	$35,890

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2003 and 2002

	2003	2002
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$1,337	$1,892
Short-term Debt	326	2,739
Long-term Debt Due Within One Year*	1,779	1,327
Risk Management Liabilities	631	961
Accrued Taxes	620	556
Accrued Interest	207	181
Customer Deposits	379	186
Other	703	814
TOTAL	5,982	8,656
NON-CURRENT LIABILITIES		
Long-term Debt*	12,322	8,863
Long-term Risk Management Liabilities	335	435
Deferred Income Taxes	3,957	3,916
Regulatory Liabilities and Deferred Investment Tax Credits	2,259	939
Asset Retirement Obligations and Nuclear Decommissioning Trusts	651	638
Employee Benefits and Pension Obligations	667	987
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	176	185
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	76	-
Deferred Credits and Other	508	1,691
TOTAL	20,951	17,654
Liabilities Held for Sale	1,876	1,279
Liabilities of Discontinued Operations	-	12
TOTAL LIABILITIES	28,809	27,601
Cumulative Preferred Stocks of Subsidiaries not Subject to Mandatory Redemption	61	-
Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries	-	321
Minority Interest in Finance Subsidiary	-	759
Cumulative Preferred Stocks of Subsidiaries	-	145
Commitments and Contingencies		
COMMON SHAREHOLDERS' EQUITY		
Common Stock-Par Value $6.50:		
2003 / 2002		
Shares Authorized..........600,000,000 / 600,000,000		
Shares Issued..............404,016,413 / 347,835,212		
(8,999,992 shares were held in treasury at December 31, 2003 and 2002)	2,626	2,261
Paid-in Capital	4,184	3,413
Retained Earnings	1,490	1,999
Accumulated Other Comprehensive Income (Loss)	(426)	(609)
TOTAL	7,874	7,064
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$36,744	$35,890

* See Accompanying Schedules

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in millions)	
OPERATING ACTIVITIES			
Net Income (Loss)	$110	$(519)	$971
Plus: Discontinued Operations	605	654	(41)
Income from Continuing Operations	715	135	930
Adjustments for Noncash Items:			
Depreciation and Amortization	1,299	1,375	1,267
Deferred Income Taxes	163	63	151
Deferred Investment Tax Credits	(33)	(31)	(29)
Pension and Postemployment Benefits Reserves	(74)	39	(234)
Cumulative Effect of Accounting Changes	(193)	350	(18)
Asset and Investment Value Impairments and Other Related Charges	720	639	-
Extraordinary Loss	-	-	48
Amortization of Deferred Property Taxes	(2)	(16)	43
Amortization of Cook Plant Restart Costs	40	40	40
Mark to Market of Risk Management Contracts	(122)	275	(294)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable, net	363	(238)	1,769
Fuel, Materials and Supplies	(71)	(102)	(82)
Accounts Payable	(632)	(21)	(469)
Taxes Accrued	87	(222)	(150)
Over/Under Fuel Recovery	138	13	340
Change in Other Assets	(162)	(78)	(171)
Change in Other Liabilities	72	(154)	(323)
Net Cash Flows From Operating Activities	2,308	2,067	2,818
INVESTING ACTIVITIES			
Construction Expenditures	(1,358)	(1,685)	(1,646)
Business Acquisitions	-	-	(1,269)
Investment in Discontinued Operations, net	(615)	-	(983)
Proceeds from Sale of Assets	82	1,263	648
Other	3	44	(42)
Net Cash Flows Used For Investing Activities	(1,888)	(378)	(3,292)
FINANCING ACTIVITIES			
Issuance of Common Stock	1,142	656	11
Issuance of Long-term Debt	4,761	2,893	2,787
Issuance of Minority Interest	-	-	744
Issuance of Equity Unit Senior Notes	-	334	-
Change in Short-term Debt, net	(2,781)	(1,248)	(778)
Retirement of Long-term Debt	(2,707)	(2,513)	(1,549)
Retirement of Preferred Stock	(9)	(10)	(5)
Retirement of Minority Interest	(225)	-	-
Dividends Paid on Common Stock	(618)	(793)	(773)
Net Cash Flows From (Used For) Financing Activities	(437)	(681)	437
Effect of Exchange Rate Change on Cash	-	(3)	(1)
Net Increase (Decrease) in Cash and Cash Equivalents	(17)	1,005	(38)
Cash and Cash Equivalents at Beginning of Period	1,199	194	232
Cash and Cash Equivalents at End of Period	$1,182	$1,199	$194
Net Increase (Decrease) in Cash and Cash Equivalents from Discontinued Operations	$(10)	$(116)	$29
Cash and Cash Equivalents from Discontinued Operations – Beginning of Period	23	139	110
Cash and Cash Equivalents from Discontinued Operations – End of Period	$13	$23	$139

See Notes to Consolidated Financial Statements.

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

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	331	$2,152	$2,915	$3,090	$(103)	$8,054
Issuance of Common Stock		1	9			10
Common Stock Dividends				(773)		(773)
Other			(18)	8		(10)
TOTAL						7,281
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					(14)	(14)
Unrealized Losses on Cash Flow Hedges					(3)	(3)
Minimum Pension Liability					(6)	(6)
NET INCOME				971		971
TOTAL COMPREHENSIVE INCOME						948
DECEMBER 31, 2001	331	$2,153	$2,906	$3,296	$(126)	$8,229
Issuance of Common Stock	17	108	568			676
Common Stock Dividends				(793)		(793)
Common Stock Expense			(30)			(30)
Other			(31)	15		(16)
TOTAL						8,066
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					117	117
Unrealized Losses on Cash Flow Hedges					(13)	(13)
Unrealized Losses on Securities Available for Sale					(2)	(2)
Minimum Pension Liability					(585)	(585)
NET LOSS				(519)		(519)
TOTAL COMPREHENSIVE INCOME (LOSS)						(1,002)
DECEMBER 31, 2002	348	$2,261	$3,413	$1,999	$(609)	$7,064
Issuance of Common Stock	56	365	812			1,177
Common Stock Dividends				(618)		(618)
Common Stock Expense			(35)			(35)
Other			(6)	(1)		(7)
TOTAL						7,581
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					106	106
Unrealized Losses on Cash Flow Hedges					(78)	(78)
Unrealized Gains on Securities Available for Sale					1	1
Minimum Pension Liability					154	154
NET INCOME				110		110
TOTAL COMPREHENSIVE INCOME						293
DECEMBER 31, 2003	404	$2,626	$4,184	$1,490	$(426)	$7,874

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES
December 31, 2003 and 2002

	December 31, 2003			
	Call Price Per Share(a)	Shares Authorized(b)	Shares Outstanding(d)	Amount (in millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	607,940	$61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	$100	1,950,000	278,100	28
6.25% - 6.875% (c)	$100	1,650,000	482,450	48
Total Subject to Mandatory Redemption (c)				76
Total Preferred Stock				$137 (e)

	December 31, 2002			
	Call Price Per Share(a)	Shares Authorized(b)	Shares Outstanding(d)	Amount (in millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	608,150	$61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	$100	1,950,000	333,100	33
6.02% - 6.875% (c)	$100	1,650,000	513,450	51
Total Subject to Mandatory Redemption (c)				84
Total Preferred Stock				$145

(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, 2003, the subsidiaries had 13,780,352 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,768,561 shares of no par value preferred stock that were authorized but unissued.

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

(d) The number of shares of preferred stock redeemed is 86,210 shares in 2003, 106,458 shares in 2002 and 50,000 shares in 2001.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
December 31, 2003 and 2002

Maturity	Weighted Average Interest Rate December 31, 2003	Interest Rates at December 31, 2003	Interest Rates at December 31, 2002	December 31, 2003 (in millions)	December 31, 2002 (in millions)
FIRST MORTGAGE BONDS (a)					
2003-2004	7.40%	6.125%-7.85%	6.00%-7.85%	$231	$648
2005-2008	6.90%	6.20%-8.00%	6.20%-8.00%	463	463
2022-2025	7.28%	6.875%-8.00%	6.875%-8.70%	246	773
INSTALLMENT PURCHASE CONTRACTS (b)(f)					
2003-2009	3.74%	2.15%-6.90%	3.75%-7.70%	395	396
2011-2030	4.92%	1.10%-8.20%	1.35%-8.20%	1,631	1,284
NOTES PAYABLE (c)(f)					
2003-2017	5.20%	1.537%-15.45%	6.225%-9.60%	1,518	214
SENIOR UNSECURED NOTES					
2003-2005	5.10%	2.43%-7.45%	2.12%-7.45%	1,359	1,834
2006-2015	5.49%	3.60%-6.91%	4.31%-6.91%	4,873	2,295
2032-2038	6.41%	5.625%-7.375%	6.00%-7.375%	1,765	690
JUNIOR DEBENTURES					
2025-2038	-	-	7.60%-8.72%	-	205
SECURITIZATION BONDS					
2005-2016	5.53%	3.54%-6.25%	3.54%-6.25%	746	797
NOTES PAYABLE TO TRUST (d)					
2037-2043	7.06%	5.25-8.00%	-	331	-
EQUITY UNIT SENIOR NOTES (e)					
2007	5.75%	5.75%	5.75%	345	345
OTHER LONG-TERM DEBT (g)				247	247
Equity Unit Contract Adjustment Payments				19	31
Unamortized Discount (net)				(68)	(32)
Total Long-term Debt Outstanding				14,101	10,190
Less Portion Due Within One Year				1,779	1,327
Long-term Portion				$12,322	$8,863

(a) First mortgage bonds are secured by first mortgage liens on electric property, plant and equipment.

(b) 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.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) Notes Payable to Trust is a result of a deconsolidation of TCC, PSO and SWEPCo's trusts effective July 1, 2003 due to the implementation of FIN 46. See Notes 2 and 17 for further information.

(e) In May 2005, the interest rate on these Equity Unit Senior Notes can be reset through a remarketing.

(f) Installment Purchase Contracts and Notes Payable include $257 million and $185 million, respectively, due to the implementation of FIN 46 (see Note 2). Notes Payable includes $496 million of a merchant power generation facility which was consolidated as of December 31, 2003 (see Notes 10 and 16).

(g) Other long-term debt consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 7) and a financing obligation under a sale and leaseback agreement.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2003 IS PAYABLE AS FOLLOWS:

	2004	2005	2006	2007 (in millions)	2008	Later Years	TOTAL
Principal Amount	$1,779	$1,273	$2,187	$1,124	$587	$7,200	$14,150
Equity Unit Contract Adjustment Payments							19
Unamortized Discount							(68)
							$14,101

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

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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Our principal business conducted by our eleven domestic electric utility operating companies is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and Europe. In addition, our domestic operations include non-regulated independent power and cogeneration facilities, coal mining and intra-state natural gas operations in Louisiana and Texas.

International operations include the generation and supply of power in the United Kingdom, and to a lesser extent in Mexico, Australia and China. These operations are either wholly-owned or partially-owned by our various subsidiaries.

We also conduct domestic barging operations, provide various energy related services and furnish communications-related services domestically.

During 2003 we announced plans to significantly restructure and dispose of many of our non-regulated operations. See Note 10 for a discussion of the impacts of these plans on our organization.

Certain previously reported amounts have been reclassified to conform to current classifications with no effect on net income or shareholders' equity.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

We are 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 rates. The prices charged by foreign subsidiaries located in China and Mexico are regulated by the authorities of those countries and are generally subject to price controls.

Principles of Consolidation

Our consolidated financial statements include AEP and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries or substantially controlled variable interest entities. Intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Other Income. We also have generating units that are jointly owned with unaffiliated companies. The proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Operations and the investments are reflected in our Consolidated Balance Sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of cost-based rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues. We discontinued the application of SFAS 71 for the generation portion of our business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June

2000, in Texas by TCC, TNC, and SWEPCo in September 1999, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December 2003. During 2003, APCo reapplied SFAS 71 for West Virginia and SWEPCo reapplied SFAS 71 for Arkansas.

Use of Estimates

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

Property, Plant and Equipment

Domestic electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the non-regulated operations and other investments are stated at their fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are deducted from accumulated depreciation. For non-regulated operations, retirements from the plant accounts and associated salvage are deducted from accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses. Assets are tested for impairment as required under SFAS 144 (see Note 10).

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For non-regulated operations, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." Capitalized interest is also recorded for domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting. The amounts of AFUDC and interest capitalized were not material in 2003, 2002 and 2001.

Depreciation, Depletion and Amortization

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

Functional Class of Property	Annual Composite Depreciation Rates Ranges		
	2003	2002	2001
Production:			
Steam-Nuclear	2.5% to 3.4%	2.5% to 3.4%	2.5% to 3.4%
Steam-Fossil-Fired	2.3% to 4.6%	2.6% to 4.5%	2.5% to 4.5%
Hydroelectric-Conventional and Pumped Storage	1.9% to 3.4%	1.9% to 3.4%	1.9% to 3.4%
Transmission	1.7% to 2.8%	1.7% to 3.0%	1.7% to 3.1%
Distribution	3.3% to 4.2%	3.3% to 4.2%	2.7% to 4.2%
Other	1.8% to 16.7%	1.8% to 9.9%	1.8% to 15.0%

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs were $0.25 per ton in 2003, $0.32 per ton in 2002 and $2.06 per ton in 2001. In 2002, certain coal-mining assets were impaired by $60 million leading to the decline in amortization rates in 2003. In 2001, an AEP subsidiary sold coal mines in Ohio and West Virginia leading to the decline in amortization rates in 2002.

Valuation of Non-Derivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Cash and Cash Equivalents

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

Inventory

Except for PSO, TCC and TNC, the regulated domestic utility companies value fossil fuel inventories using a weighted average cost method. PSO, TCC and TNC, utilize the LIFO method to value fossil fuel inventories. For those domestic utilities whose generation is unregulated, inventory of coal and oil is carried at the lower of cost or market. Coal mine inventories are also carried at the lower of cost or market. Materials and supplies inventories are carried at average cost. Non-trading gas inventory is carried at the lower of cost or market. During 2003 a fair value hedging strategy was implemented for certain non-trading gas and coal inventory. Changes in the fair value of hedged inventory are recorded to the extent offsetting hedges are designated against that inventory.

Accounts Receivable

Customer accounts receivable primarily includes receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power and gas sales when we deliver power or gas to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the latest billings.

AEP Credit, Inc. factors accounts receivable for certain registrant subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of the company's balance sheet. See Note 17 "Financing Activities" for further details.

Foreign Currency Translation

The financial statements of subsidiaries outside the U.S. which are included in our 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." Although the effects of foreign currency fluctuations are mitigated by the fact that expenses of foreign subsidiaries are generally incurred in the same currencies in which sales are generated, the reported results of operations of our foreign subsidiaries are affected by changes in foreign currency exchange rates and, as compared to prior periods, will be higher or lower depending upon a weakening or strengthening of the U.S. dollar. Revenues and expenses are translated at monthly average foreign currency exchange rates throughout the year. Assets and liabilities are translated into U.S. dollars at year-end foreign currency exchange rates. Accordingly, our consolidated common shareholders' equity will fluctuate depending on the relative strengthening or weakening of the U.S. dollar versus relevant foreign currencies. Currency translation gain and loss adjustments are recorded in shareholders' equity as Accumulated Other Comprehensive Income (Loss). The impact of the changes in exchange rates on cash, resulting from the translation of items at different exchange rates, is shown on our Consolidated

Statements of Cash Flows in Effect of Exchange Rate Change on Cash. Actual currency transaction gains and losses are recorded in income when they occur.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amounts of an over-recovery or under-recovery can also be affected by actions of regulators. When these actions become probable we adjust our deferrals to recognize these probable outcomes. The amount of under-recovered fuel costs deferred under fuel clauses as a regulatory asset was $51 million at December 31, 2003 and $148 million at December 31, 2002. The amount of over-recovered fuel costs deferred under fuel clauses as a regulatory liability was $132 million at December 31, 2003 and $90 million at December 31, 2002. See Note 5 "Effects of Regulation" for further information.

In general, changes in fuel costs in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo are timely reflected in rates through the fuel cost adjustment clauses in place in those states. Where fuel clauses have been eliminated due to the transition to market pricing, (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002) changes in fuel costs impact earnings. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes have also impacted earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze is scheduled to end on March 1, 2004. Changes in fuel costs also impact earnings for certain of our Independent Power Producer generating units that do not have long-term contracts for their fuel supply. See Note 4, "Rate Matters" and Note 6, "Customer Choice and Industry Restructuring" for further information about fuel recovery.

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers through regulated revenues in the same accounting period. Regulatory liabilities or regulatory assets are also recorded for unrealized gains or losses that occur due to changes in the fair value of physical and financial contracts that are derivatives and that are subject to the regulated ratemaking process.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our statement of operations when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Domestic Gas Pipeline and Storage Activities

Revenues are recognized from domestic gas pipeline and storage services when gas is delivered to contractual meter points or when services are provided, with the exception of certain physical forward gas purchase and sale contracts that are derivatives and that are accounted for using mark-to-market accounting (Resale Gas Contracts).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in October 2002, these activities were focused on wholesale markets where we own assets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, we recorded wholesale marketing and risk management activities using the mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. We implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into prior to October 25, 2002, we implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change.

After January 1, 2003, we use mark-to-market accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and Rescission of EITF 98-10 in Note 2.

Accounting for Derivative Instruments

We use the mark-to-market method of accounting for derivative contracts. Unrealized gains and losses prior to settlement, resulting from revaluation of these contracts to fair value during the period, are recognized currently. When the derivative contracts are settled and gains and losses are realized, the previously recorded unrealized gains and losses from mark-to-market valuations are reversed.

Certain derivative instruments are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the Consolidated Statement of Operations in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income and subsequently reclassified into Revenues in the Consolidated Statement of Operations when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the Consolidated Statement of Operations immediately (see Note 14).

The fair values of derivative instruments accounted for using mark-to-market accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. We have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

We recognize all derivative instruments at fair value in our Consolidated Balance Sheets as either "Risk Management Assets" or "Risk Management Liabilities." We do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in Revenues in the Consolidated Statement of Operations on a net basis, with the exception of physically settled Resale Gas Contracts for the purchase of natural gas. The unrealized and realized gains and losses on these Resale Gas Contracts are presented as Purchased Gas for Resale in the Consolidated Statement of Operations.

Construction Projects for Outside Parties

Our entities engage in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue in proportion to costs incurred compared to total estimated costs.

Debt Instrument Hedging and Related Activities

In order to mitigate the risks of market price and interest rate fluctuations, we enter into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory hedges 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, 2003 or 2002.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that we will recover specifically incurred costs through future rates a regulatory asset is established to match the expensing of maintenance costs with their recovery in cost-based regulated revenues.

Other Income and Other Expenses

Non-operational revenue including the nonregulated business activities of our utilities, equity earnings of non-consolidated subsidiaries, gains on dispositions of property, interest and dividends, AFUDC and miscellaneous income, are reported in Other Income. Non-operational expenses including nonregulated business activities of our utilities, losses on dispositions of property, miscellaneous amortization, donations and various other non-operating and miscellaneous expenses, are reported in Other Expenses.

AEP Consolidated Other Income and Deductions:

	2003	December 31, 2002 (in millions)	2001
Other Income:			
Equity Earnings (Loss)	$10	$(15)	$30
Non-operational Revenue	129	201	184
Interest	42	26	48
Gain on Sale of Frontera	-	-	73
Gain on Sale of REPs (Mutual Energy Companies)	39	129	-
Other	167	120	36
Total Other Income	$387	$461	$371
Other Expenses:			
Property Taxes	$20	$20	$15
Non-operational Expenses	112	179	76
Fiber Optic and Datapult Exit Costs	-	-	49
Provision for Loss - Airplane	-	-	14
Other	95	124	71
Total Other Expenses	$227	$323	$225

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customer. We do not recognize these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt, associated with the regulated business, is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Other Income and Other Expenses.

Debt discount or premium and debt issuance expenses are deferred and amortized utilizing the effective interest rate method over the term of the related debt. The amortization expense is included in interest charges.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings consistent with the timing of its inclusion in rates in accordance with SFAS 71.

Goodwill and Intangible Assets

When we acquire businesses we record the fair value of any acquired goodwill and other intangible assets. Purchased goodwill and intangible assets with indefinite lives are not amortized. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually. Intangible assets with finite lives are amortized over their respective estimated lives to their estimated residual values.

The policies described above became effective with our adoption of a new accounting standard for goodwill (SFAS 142). For all business combinations with an acquisition date before July 1, 2001, we amortized goodwill and intangible assets with indefinite lives through December 2001, and then ceased amortization. The goodwill associated with those business combinations with an acquisition date before July 1, 2001 was amortized on a straight-line basis generally over 40 years except for the portion of goodwill associated with gas trading and marketing activities which was amortized on a straight-line basis over 10 years. Intangible assets with finite lives continue to be amortized over their respective estimated lives ranging from 2 to 10 years.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed us to collect through rates to fund future decommissioning and spent fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) and the FERC have established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above)
- Maximum percentage invested in a specific type of investment
- Prohibition of investment in obligations of the applicable company or its affiliates

Trust funds are maintained for each regulatory jurisdiction and managed by investment managers external to AEP, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after-tax earnings of the trust, giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Spent Nuclear Fuel and Decommissioning Trusts for amounts relating to the Cook Plant and are included in Assets Held for Sale for amounts relating to the Texas Plants. See "Assets Held for Sale" section of Note 10 for further information regarding the Texas Plants. These securities are recorded at market value. Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Unrealized gains and losses from securities in these trust funds are reported as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheet in the equity section. The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

Components	December 31, 2003	2002	2001
	(in millions)		
Foreign Currency Translation Adjustments	$110	$4	$(113)
Unrealized Losses on Securities Available for Sale	(1)	(2)	-
Unrealized Losses on Cash Flow Hedges	(94)	(16)	(3)
Minimum Pension Liability	(441)	(595)	(10)
Total	$(426)	$(609)	$(126)

Stock Based Compensation Plans

At December 31, 2003, we have two stock-based employee compensation plans with outstanding stock options, which are described more fully in Note 12. No stock option expense is reflected in our earnings, as all options granted under these plans had exercise prices equal to or above the market value of the underlying common stock on the date of grant.

We also grant performance share units, phantom stock units, restricted shares and restricted stock units to employees, as well as stock units to non-employee members of the Board of Directors. The Deferred Compensation and Stock Plan for Non-Employee Directors permits directors to choose to defer up to 100 percent of their annual Board retainer in stock units, and the Stock Unit Accumulation Plan for Non-Employee Directors awards stock units to directors. Compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director's stock units.

We do not currently intend to adopt the fair-value-based method of accounting for stock options. The following table shows the effect on our Net Income (Loss) and Earnings (Loss) per Share as if we had applied fair value measurement and recognition provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation awards:

	Year Ended December 31, 2003	2002	2001
	(in millions, except per share data)		
Net Income (Loss), as reported	$110	$(519)	$971
Add: Stock-based compensation expense included in reported net income, net of related tax effects	2	(5)	3
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(7)	(4)	(15)
Pro Forma Net Income (Loss)	$105	$(528)	$959
Earnings (Loss) per Share:			
Basic – as Reported	$0.29	$(1.57)	$3.01
Basic – Pro Forma (a)	$0.27	$(1.59)	$2.98
Diluted – as Reported	$0.29	$(1.57)	$3.01
Diluted – Pro Forma (a)	$0.27	$(1.59)	$2.97

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

Earnings Per Share (EPS)

Basic earnings (loss) per common share is calculated by dividing net earnings (loss) available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards. The effects of stock options have not been included in the fiscal 2002 diluted loss per common share calculation as their effect would have been anti-dilutive.

The calculation of our basic and diluted earnings (loss) per common share (EPS) is based on weighted average common shares shown in the table below:

	2003	2002	2001
	(in millions – except per share amounts)		
Weighted Average Shares:			
Average Common Shares Outstanding	385	332	322
Assumed Conversion of Dilutive Stock Options (see Note 12)	-	-	1
Diluted Average Common Shares Outstanding	385	332	323

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share. Our basic and diluted EPS are the same in 2003, 2002 and 2001 since the effect on weighted average common shares outstanding is minimal.

Had we reported net income in fiscal 2002, incremental shares attributable to the assumed exercise of outstanding stock options would have increased diluted common shares outstanding by 398,000 shares.

Options to purchase 5.6 million, 8.8 million and 0.7 million shares of common stock were outstanding at December 31, 2003, 2002 and 2001, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the year-end market price of the common shares and, therefore, the effect would be antidilutive.

In addition, there is no effect on diluted earnings per share related to our equity units (issued in 2002) unless the market value of our common stock exceeds $49.08 per share. There were no dilutive effects from equity units at December 31, 2003 and 2002. If our common stock value exceeds $49.08 we would apply the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contracts are used to repurchase outstanding shares. Also see Note 17.

Supplementary Information

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
AEP Consolidated Purchased Power – Ohio Valley Electric Corporation (44.2% owned by AEP System)	$147	$142	$127
Cash was paid for:			
Interest (net of capitalized amounts)	$741	$792	$972
Income Taxes	$163	$336	$569
Noncash Investing and Financing Activities:			
Acquisitions under Capital Leases	$25	$6	$17
Assumption of Liabilities Related to Acquisitions	$-	$1	$171
Increase in assets and liabilities resulting from:			
Consolidation of VIEs due to the adoption of FIN 46 (see Note 2)	$547	$-	$-
Consolidation of merchant power generation facility (see Note 16)	$496	$-	$-
Exchange of Communication Investment for Common Stock	$-	$-	$5

Power Projects

We own interests of 50% or less in domestic unregulated power plants with a capacity of 1,043 MW located in Colorado, Florida and Texas. In addition to the domestic projects, we have interests of 50% or less in international power plants totaling 1,113 MW (see Note 10, "Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used").

Investments in power projects that are 50% or less owned are accounted for by the equity method and reported in Investments in Power and Distribution Projects on our Consolidated Balance Sheets (see "Eastex" within the Dispositions section of Note 10). At December 31, 2003, five domestic power projects and three international power investments are accounted for under the equity method. The five domestic projects are combined cycle gas turbines that provide steam to a host commercial customer and are considered either Qualifying Facilities (QFs) or Exempt Wholesale Generators (EWGs) under PURPA. The three international power investments are classified as Foreign Utility Companies (FUCO) under the Energy Policies Act of 1992. Two of the international investments are power projects and the other international investment is a company which owns an interest in four additional power projects. All of the power projects accounted for under the equity method have unrelated third-party partners.

Seven of the above power projects have project-level financing, which is non-recourse to AEP. AEP or AEP subsidiaries have guaranteed $8 million of domestic partnership obligations for performance under power purchase agreements and for debt service reserves in lieu of cash deposits. In addition, AEP has issued letters of credit with maximum future payments of $23 million for domestic power projects and $69 million for international power investments.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income (Loss).

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

SFAS 132 (revised 2003) "Employers' Disclosure about Pensions and Other Postretirement Benefits"

In December 2003 the FASB issued SFAS 132 (revised 2003), which requires additional footnote disclosures about pensions and postretirement benefits, some of which are effective beginning with the year-end 2003 financial statements. Other additional disclosures will begin with our 2004 quarterly financial statements or our 2004 year-end financial statements.

We will implement new quarterly disclosures when they become effective in the first quarter of 2004, including (a) the amount of net periodic benefit cost for each period for which an income statement is presented, showing separately each component thereof, and (b) the amount of employer contributions paid and expected to be paid during the current year, if significantly different from amounts disclosed at the most recent year-end.

We will implement the new year-end disclosure when it becomes effective in the fourth quarter of 2004, concerning information about foreign plans, if appropriate. See Note 11 for these additional 2003 disclosures.

SFAS 142 "Goodwill and Other Intangible Assets"

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, and that goodwill and intangible assets be tested annually for impairment. The implementation of SFAS 142 resulted in a $350 million after tax net transitional loss in 2002 for the U.K. and Australian operations and is reported in our Consolidated Statements of Operations as a cumulative effect of accounting change. See Note 3 for further information on goodwill and other intangible assets.

SFAS 143 "Accounting for Asset Retirement Obligations"

We implemented SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003, which requires entities to record a liability at fair value for any legal obligations for asset retirements in the period incurred. Upon establishment of a legal liability, SFAS 143 requires a corresponding asset to be established which will be depreciated over its useful life. SFAS 143 requires that a cumulative effect of change in accounting principle be recognized for the cumulative accretion and accumulated depreciation that would have been recognized had SFAS 143 been applied to existing legal obligations for asset retirements. In addition, the cumulative effect of change in accounting principle is favorably affected by the reversal of accumulated removal cost. These costs had previously been recorded for generation and did not qualify as a legal obligation although these costs were collected in depreciation rates by certain formerly regulated subsidiaries.

We completed a review of our asset retirement obligations and concluded that we have related legal liabilities for nuclear decommissioning costs for our Cook Plant and our partial ownership in the South Texas Project, as well as liabilities for the retirement of certain ash ponds, wind farms, the U.K. Plants, and certain coal mining facilities. Since we presently recover our nuclear decommissioning costs in our regulated cash flow and have existing balances recorded for such nuclear retirement obligations, we recognized the cumulative difference between the amount already provided through rates and the amount as measured by applying SFAS 143 as a regulatory asset or liability. Similarly, a regulatory asset was recorded for the cumulative effect of certain retirement costs for ash ponds related to our regulated operations. In 2003, we recorded an unfavorable cumulative effect of $45.4 million after tax for our non-regulated operations ($38.0 million related to Ash Ponds in the Utility Operations segment, $7.2 million related to U.K. Plants in the Investments – UK Operations segment and $0.2 million for Wind Mills in the Investments – Other segment).

Certain of our utility operating companies have collected removal costs from ratepayers for certain assets that do not have associated legal asset retirement obligations. To the extent that operating companies have now been deregulated we reversed the balance of such removal costs, totaling $287.2 million, after tax, which resulted in a net favorable cumulative effect in 2003. We have reclassified approximately $1.2 billion of removal costs for our utility operations from accumulated depreciation to Regulatory Liabilities and Deferred Investment Tax Credits in 2003 and to Deferred Credits and Other in 2002. In addition, $9 million is classified as held-for-sale related to the TCC generation assets as of December 31, 2003 and 2002.

The net favorable cumulative effect of the change in accounting principle for the year ended December 31, 2003 consists of the following:

	Pre-tax Income (Loss)	After-tax Income (Loss)
	(in millions)	
Ash Ponds	$(62.8)	$(38.0)
U.K. Plants, Wind Mills and Coal Operations	(11.3)	(7.4)
Reversal of Cost of Removal	472.6	287.2
Total	$398.5	$241.8

We have identified, but not recognized, asset retirement obligation liabilities related to electric transmission and distribution and gas pipeline assets, as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements.

The following is a reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations:

	Nuclear Decommissioning	Ash Ponds	U.K. Plants, Wind Mills and Coal Operations	Total
		(in millions)		
Asset Retirement Obligation Liability at January 1, 2003	$718.3	$69.8	$37.2	$825.3
Accretion Expense	52.6	5.6	2.3	60.5
Liabilities Incurred	-		8.3	8.3
Foreign Currency Translation	-	-	5.3	5.3
Asset Retirement Obligation Liability at December 31, 2003 including Held for Sale	770.9	75.4	53.1	899.4
Less Asset Retirement Obligation Liability Held for Sale:				
South Texas Project	(218.8)	-	-	(218.8)
U.K. Plants	-	-	(28.8)	(28.8)
Asset Retirement Obligation Liability at December 31, 2003	$552.1	$75.4	$24.3	$651.8

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

As of December 31, 2003 and 2002, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $845 million and $716 million, respectively, of which $720 million and $618 million relating to the Cook Plant was recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Consolidated Balance Sheets. The fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities for the South Texas Project totaling $125 million and $98 million as of December 31, 2003 and 2002, respectively, was classified as Assets Held for Sale in our Consolidated Balance Sheets.

Pro forma net income and earnings per share are not presented for the years ended December 31, 2002 and 2001 because the pro forma application of SFAS 143 would result in pro forma net income and earnings per share not materially different from the actual amounts reported during those periods.

As of December 31, 2002 and 2001, the pro forma liability for asset retirement obligations which has been calculated as if SFAS 143 had been adopted at the beginning of each period was $825 million and $769 million, respectively.

SFAS 144 "Accounting for the Impairment or Disposal of Long-lived Assets"

In August 2001, the FASB issued SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets" which sets forth the accounting to recognize and measure an impairment loss. This standard replaced, SFAS 121, "Accounting for Long-lived Assets and for Long-lived Assets to be Disposed Of." We adopted SFAS 144 effective January 1, 2002. See Note 10 for discussion of impairments recognized in 2003 and 2002.

SFAS 145 "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections"

In April 2002, the FASB issued SFAS 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS 145). SFAS 145 rescinds SFAS 4, "Reporting Gains and Losses from Extinguishment of Debt," effective for fiscal years beginning after May 15, 2002. SFAS 4 required gains and losses from extinguishment of debt to be aggregated and classified as an extraordinary item if material. In 2003, we reclassified Extraordinary Losses (Net of Tax) on TCC's reacquired debt of $2 million for 2001 to Other Expenses.

SFAS 146 "Accounting for Costs Associated with Exit or Disposal Activities"

In June 2002, FASB issued SFAS 146 which addresses accounting for costs associated with exit or disposal activities. This statement supersedes previous accounting guidance, principally EITF No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. SFAS 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that the liability should initially be measured and recorded at fair value. The time at which we recognize future costs related to exit or disposal activities, including restructuring, as well as the amounts recognized may be affected by SFAS 146. We adopted the provisions of SFAS 146 for exit or disposal activities initiated after December 31, 2002.

SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

On April 30, 2003, the FASB issued Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends SFAS 133 to clarify the definition of a derivative and the requirements for contracts to qualify for the normal purchase and sale exemption. SFAS 149 also amends certain other existing pronouncements. Effective July 1, 2003, we implemented SFAS 149 and the effect was not material to our results of operations, cash flows or financial condition.

SFAS 150 "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"

We implemented SFAS 150 effective July 1, 2003. SFAS 150 is the first phase of the FASB's project to eliminate from the balance sheet the "mezzanine" presentation of items with characteristics of both liabilities and equity, including: (1) mandatorily redeemable shares, (2) instruments other than shares that could require the issuer to buy back some of its shares in exchange for cash or other assets and (3) certain obligations that can be settled with shares. Measurement of these liabilities generally is to be at fair value, with the payment or accrual of "dividends" and other amounts to holders reported as interest cost.

Beginning with our third quarter 2003 financial statements, we present Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption as a Non-Current Liability. Beginning July 1, 2003, we classify dividends on these mandatorily redeemable preferred shares as interest expense. In accordance with SFAS 150, dividends from prior periods remain classified as preferred stock dividends (a component of Preferred Stock Dividend Requirements of Subsidiaries).

FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"

In November 2002, the FASB issued FIN 45 which clarifies the accounting to recognize liabilities related to issuing a guarantee, as well as additional disclosures of guarantees. We implemented FIN 45 as of January 1, 2003, and the effect was not material to our results of operations, cash flows or financial condition. See Note 8 for further disclosures.

FIN 46 (revised December 2003)"Consolidation of Variable Interest Entities" and FIN 46 "Consolidation of Variable Interest Entities"

We implemented FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. FIN 46 interprets the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Due to the prospective application of FIN 46, we did not reclassify prior period amounts.

On July 1, 2003, we deconsolidated Caddis Partners, LLC (Caddis). At December 31, 2002 $759 million was reported as a Minority Interest in Finance Subsidiary. At December 31, 2003 $527 million is reported as a note payable to Caddis, a component of Long-Term Debt. See Note 17 "Financing Activities" for further disclosures.

On July 1, 2003, we also deconsolidated the trusts which hold mandatorily redeemable trust preferred securities. Therefore, of the $321 million net amount reported as "Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries" at December 31, 2002, $331 million is reported as Notes Payable to Trust (included in Long-term Debt) and $10 million is reported in Other Non-Current Assets at December 31, 2003.

Effective July 1, 2003, SWEPCo consolidated Sabine Mining Company (Sabine), a contract mining operation providing mining services to SWEPCo. Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($77.8 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of accounting change recorded as a result of our requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Effective July 1, 2003, OPCo consolidated JMG. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There is no cumulative effect of accounting change recorded as a result of our requirement to consolidate JMG, and there is no change in net income due to the consolidation of JMG. See Note 16 "Leases" for further disclosures.

In December 2003, the FASB issued FIN 46 (revised December 2003) (FIN 46R) which replaces FIN 46. The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

EITF 02-3 and Rescission of EITF 98-10

In October 2002, the Emerging Issues Task Force of the FASB reached a final consensus on Issue No. 02-3. EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Under EITF 02-3, mark-to-market accounting is precluded for risk management contracts that are not derivatives pursuant to SFAS 133. The consensus to rescind EITF 98-10 also eliminated the recognition of physical inventories at fair value other than as provided by GAAP. We have implemented this standard for all physical inventory and non-derivative risk management transactions occurring on or after October 25, 2002. For physical inventory and non-derivative risk management transactions entered into prior to October 25, 2002, we implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change. We recorded a $49 million loss, net of income tax, as a cumulative effect of accounting change.

Effective January 1, 2003, EITF 02-3 requires that gains and losses on all derivatives, whether settled financially or physically, be reported in the income statement on a net basis if the derivatives are held for risk management purposes. Previous guidance in EITF 98-10 permitted contracts that were not settled financially to be reported either gross or net in the income statement. Prior to the third quarter of 2002, we recorded and reported upon settlement, sales under forward risk management contracts as revenues; we also recorded and reported purchases under forward risk management contracts as purchased energy expenses. Effective July 1, 2002, we reclassified such forward risk management revenues and purchases on a net basis. The reclassification of such risk management activities to a net basis of reporting resulted in a substantial reduction in both revenues and purchased energy expense, but did not have any impact on our financial condition, results of operations or cash flows.

EITF 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3"

In July 2003, the EITF reached consensus on Issue No. 03-11. The consensus states that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. The adoption of EITF 03-11 did not have a material impact on our results of operations, financial position or cash flows.

FASB Staff Position No. 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

On January 12, 2004, the FASB Staff issued FSP 106-1, which allows a one-time election to defer accounting for any effects of the prescription drug subsidy under the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act), enacted on December 8, 2003. There are significant uncertainties as to whether our plan will be eligible for a subsidy under future federal regulations that have not yet been drafted. The method of accounting for any such subsidy and, therefore, the subsidy's possible reduction to our accumulated postretirement benefit obligation and periodic postretirement benefit costs has not been resolved by the FASB or other professional accounting standard setting authority. Accordingly, we elected to defer any potential effects of the Act until authoritative guidance on the accounting for the federal subsidy is issued. Our measurements of the accumulated postretirement benefit obligation and periodic postretirement benefit cost included in these financial statements do not reflect any potential effects of the Act. We cannot determine what impact, if any, new authoritative guidance on the accounting for the federal subsidy may have on our results of operations or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing. Until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. We recorded a $49 million after tax charge against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in Cumulative Effect of Accounting Changes in the first quarter of 2003 ($12 million in Utility Operations, $22 million in Investments – Gas Operations and $15 million in Investments – UK Operations segments). This amount will be realized when the positions settle.

The FASB's Derivative Implementation Group (DIG) issued accounting guidance under SFAS 133 for certain derivative fuel supply contracts with volumetric optionality and derivative electricity capacity contracts. This guidance, effective in the third quarter of 2001, concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when certain option-type contracts and forward contracts in electricity can qualify for the normal purchase or sale exclusion.

The effect of initially adopting the DIG guidance at July 1, 2001 was a favorable earnings mark-to-market after tax effect of $18 million (net of tax of $2 million). It was reported as a cumulative effect of an accounting change on our Consolidated Statements of Operations (included in Investments - Other segment).

Asset Retirement Obligations (SFAS 143)

In the first quarter of 2003, we recorded $242 million in after-tax income as a cumulative effect of accounting change for Asset Retirement Obligations.

Goodwill and Other Intangible Assets

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized and be tested annually for impairment. The implementation of SFAS 142 in 2002 resulted in a $350 million net transitional loss for our U.K. and Australian operations (included in the Investments – Other segment) and is reported in our Consolidated Statements of Operations as a cumulative effect of accounting change (see Note 3, "Goodwill and Other Intangible Assets" for further details).

See table below for details of the Cumulative Effect of Accounting Changes:

Description	Year Ended December 31. 2003	2002	2001
		(in millions)	
Accounting for Risk Management Contracts (EITF 02-3)	$(49)	$-	$-
Asset Retirement Obligations (SFAS 143)	242	-	-
Goodwill and Other Intangible Assets	-	(350)	-
Accounting for Risk Management Contracts (DIG Guidance)	-	-	18
Total	$193	$(350)	$18

EXTRAORDINARY ITEMS

In 2001, we recorded an extraordinary item for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of our business in the Ohio state jurisdiction. OPCo and CSPCo recognized an extraordinary loss of $48 million (net of tax of $20 million) for unrecoverable Ohio Public Utility Excise Tax (commonly known as the Gross Receipts Tax – GRT) net of allowable Ohio coal credits. This loss resulted from regulatory decisions in connection with Ohio deregulation which stranded the recovery of the GRT. Effective with the liability affixing on May 1, 2001, CSPCo and OPCo recorded an extraordinary loss under SFAS 101. Both Ohio companies appealed to the Ohio Supreme Court the PUCO order on Ohio restructuring that the Ohio companies believe failed to provide for recovery for the final year of the GRT. In April 2002, the Ohio Supreme Court denied recovery of the final year of the GRT.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

GOODWILL

The changes in our carrying amount of goodwill for the years ended December 31, 2003 and 2002 by operating segment are:

	Utility Operations	Investments Gas Operations	Investments UK Operations	Investments Other	AEP Consolidated
			(in millions)		
Balance at January 1, 2002 (including Assets Held for Sale)	$37.1	$340.1	$-	$14.9	$392.1
Goodwill acquired	-	-	2.3	-	2.3
Changes to Goodwill due to Purchase price adjustments	-	(33.8)	172.5	42.4	181.1
Impairment losses	-	-	(170.0)	(15.9)	(185.9)
Foreign currency exchange rate changes	-	-	6.4	-	6.4
Balance at December 31, 2002 (including Assets Held for Sale)	37.1	306.3	11.2	41.4	396.0
Less: Assets Held for Sale, Net (a)	-	(143.8)	(11.2)	-	(155.0)
Balance at December 31, 2002 (excluding Assets Held for Sale)	$37.1	$162.5	$-	$41.4	$241.0
Balance at January 1, 2003 (including Assets Held for Sale)	$37.1	$306.3	$11.2	$41.4	$396.0
Impairment losses	-	(291.4)	(12.2)	-	(303.6)
Foreign currency exchange rate changes	-	-	1.0	-	1.0
Balance at December 31, 2003 (including Assets Held for Sale)	37.1	14.9	-	41.4	93.4
Less: Assets Held for Sale, Net (a)	-	(14.9)	-	-	(14.9)
Balance at December 31, 2003 (excluding Assets Held for Sale)	$37.1	$-	$-	$41.4	$78.5

(a) On our Consolidated Balance Sheets, amounts related to entities classified as held for sale are excluded from Goodwill and are reported within Assets Held for Sale (see Note 10). The following entities classified as held for sale had goodwill or goodwill impairments during the years ended December 31, 2003 or 2002:

- Jefferson Island (Investments – Gas Operations segment) – $14.4 million and $143.3 million balances in goodwill at December 1, 2003 and 2002, respectively. During 2003, we recognized a goodwill impairment loss of $128.9 million.
- LIG Chemical (Investments – Gas Operations segment) – $0.5 million balance in goodwill at December 31, 2003 and 2002.
- U.K. Coal Trading (Investments – UK Operations segment) – $11.2 million balance in goodwill at December 31, 2002. In 2003, we recognized a goodwill impairment loss of $12.2 million related to the impairment study (impairment in 2003 was greater than December 31, 2002 balance due to changes in foreign currency translation rates).
- U.K. Generation (Investments – UK Operations segment) – No goodwill balances at December 31, 2003 or 2002. In 2002, we recognized a goodwill impairment loss of $166.0 million related to the impairment study.
- AEP Coal (Investments – Other segment) – No goodwill balances at December 31, 2003 or 2002. In 2002, we recognized a $3.6 million impairment loss related to the impairment study.

Accumulated amortization of goodwill was approximately $1 million and $9 million at December 31, 2003 and 2002, respectively. The decrease of $8 million between years is related to the impairment of goodwill on Houston Pipe Line Company and AEP Energy Services.

In the fourth quarter of 2003, we prepared our annual goodwill impairment tests. The fair values of the operations were estimated using cash flow projections and other market value indicators. As a result of the tests, we recognized a $162.5 million goodwill impairment loss related to Houston Pipe Line Company ($150.4 million) and AEP Energy Services ($12.1 million).

During 2002, changes to goodwill were due to purchase price adjustments of $6.7 million primarily related to our acquisition of Houston Pipe Line Company, MEMCO and Nordic Trading (see Note 10).

In the first quarter of 2002, we recognized a goodwill impairment loss of $12.3 million for all goodwill related to Gas Power Systems (see Note 10).

In the fourth quarter of 2002, we prepared our annual goodwill impairment tests. The fair values of the operations were estimated using cash flow projections. As a result of the tests, we recognized a goodwill impairment loss of $4.0 million related to Nordic Trading (see Note 10).

The transitional impairment loss related to SEEBOARD and CitiPower goodwill, which is reported as Cumulative Effect of Accounting Changes in 2002, is excluded from the above schedule.

The following tables show the transitional disclosures to adjust our reported net income (loss) and earnings (loss) per share to exclude amortization expense recognized in prior periods related to goodwill and intangible assets that are no longer being amortized.

Net Income (Loss)	**Year Ended December 31,**		
	2003	**2002**	**2001**
		(in millions)	
Reported Net Income (Loss)	$110	$(519)	$971
Add back: Goodwill amortization	-	-	39(a)
Add back: Amortization for intangibles with indefinite lives	-	-	8(b)
Adjusted Net Income (Loss)	$110	$(519)	$1,018

Earnings (Loss) Per Share (Basic and Dilutive)	**Year Ended December 31,**		
	2003	**2002**	**2001**
Reported Earnings (Loss) per Share	$0.29	$(1.57)	$3.01
Add back: Goodwill amortization	-	-	0.12(c)
Add back: Amortization for intangibles with indefinite lives	-	-	0.02(b)
Adjusted Earnings (Loss) per Share	$0.29	$(1.57)	$3.15

(a) This amount includes $34 million in 2001 related to SEEBOARD and CitiPower amortization expense included in Discontinued Operations on our Consolidated Statements of Operations.
(b) The amounts shown for 2001 relate to CitiPower amortization expense included in Discontinued Operations on our Consolidated Statements of Operations.
(c) This amount includes $0.10 in 2001 related to SEEBOARD and CitiPower amortization expense included in Discontinued Operations on our Consolidated Statements of Operations.

OTHER INTANGIBLE ASSETS

Acquired intangible assets subject to amortization are $34 million at December 31, 2003 and $37 million at December 31, 2002, net of accumulated amortization. The gross carrying amount, accumulated amortization and amortization life by major asset class are:

	Amortization Life	December 31, 2003 Gross Carrying Amount	December 31, 2003 Accumulated Amortization	December 31, 2002 Gross Carrying Amount	December 31, 2002 Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Software and customer list (a)	2	$-	$-	$0.5	$0.2
Software acquired (b)	3	0.5	0.3	0.5	-
Patent	5	0.1	-	0.1	-
Easements	10	2.2	0.3	-	-
Trade name and administration of contracts	7	2.4	0.9	2.4	0.6
Purchased technology	10	10.9	2.2	10.3	1.0
Advanced royalties	10	29.4	7.7	29.4	4.7
Total		$45.5	$11.4	$43.2	$6.5

(a) This asset was disposed of in the second quarter of 2003.
(b) This asset relates to U.K. Generation Plants and is included in Assets Held for Sale on our Consolidated Balance Sheets.

Amortization of intangible assets was $5 million and $4 million for the twelve months ended December 31, 2003 and 2002, respectively. Our estimated aggregate amortization expense is $5 million for each year 2004 through 2007, $4 million for 2008 through 2010 and $3 million in 2011.

4. RATE MATTERS

In certain jurisdictions, we have agreed to base rate or fuel recovery limitations usually under terms of settlement agreements. See Note 5 for a discussion of those terms related to Nuclear Plant Restart and Merger with CSW.

Fuel in SPP Area of Texas

In 2001, the PUCT delayed the start of customer choice in the SPP area of Texas. In May 2003, the PUCT ordered that competition would not begin in the SPP areas before January 1, 2007. TNC filed with the PUCT in 2002 to determine the most appropriate method to reconcile fuel costs in TNC's SPP area. In April 2003, the PUCT issued an order adopting the methodology proposed in TNC's filing, with adjustments, for reconciling fuel costs in the SPP area. The adjustments removed $3.71 per MWH from reconcilable fuel expense. This adjustment will reduce revenues received by Mutual Energy SWEPCo who now serves TNC's SPP customers by approximately $400,000 annually. In October 2003, Mutual Energy SWEPCo agreed with the PUCT staff and the Office of Public Utility Counsel (OPC) to file a fuel reconciliation proceeding for the period January 2002 through December 2003 by March 31, 2004 and the PUCT ordered that the filing be made.

TNC Fuel Reconciliations

In June 2002, TNC filed with the PUCT to reconcile fuel costs, requesting to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory. At December 31, 2001, the deferred under-recovery balance associated with TNC's ERCOT service area was $27.5 million including interest. During the reconciliation period, TNC incurred $293.7 million of eligible fuel costs serving both ERCOT and SPP retail customers. TNC also requested authority to surcharge its SPP customers for under-recovered fuel costs. TNC's SPP customers will continue to be subject to fuel reconciliations until competition begins in the SPP area as described above. The under-recovery balance at December 31, 2001 for TNC's service within SPP was $0.7 million including interest.

In March 2003, the ALJ in this proceeding filed a Proposal for Decision (PFD) with a recommendation that TNC's under-recovered retail fuel balance be reduced. In March 2003, TNC established a reserve of $13 million based on the recommendations in the PFD. In May 2003, the PUCT reversed the ALJ on certain matters and remanded TNC's final fuel reconciliation to the ALJ to consider two issues. The issues are the sharing of off-system sales margins from AEP's trading activities with customers for five years per the PUCT's interpretation of the Texas AEP/CSW merger settlement and the inclusion of January 2002 fuel factor revenues and associated costs in the determination of the under-recovery. The PUCT proposed that the sharing of off-system sales margins for periods beyond the termination of the fuel factor should be recognized in the final fuel reconciliation proceeding. This would result in the sharing of margins for an additional three and one half years after the end of the Texas ERCOT fuel factor.

On December 3, 2003, the ALJ issued a PFD in the remand phase of the TNC fuel reconciliation recommending additional disallowances for the two remand issues. TNC filed responses to the PFD and the PUCT announced a final ruling in the fuel reconciliation proceeding on January 15, 2004 accepting the PFD. TNC is waiting for a written order, after which it will request a rehearing of the PUCT's ruling. While management believes that the Texas merger settlement only provided for sharing of margins during the period fuel and generation costs were regulated by the PUCT, an additional provision of $10 million was recorded in December 2003. Based on the decisions of the PUCT, TNC's final under-recovery including interest at December 31, 2003 was $6.2 million.

In February 2002, TNC received a final order from the PUCT in a previous fuel reconciliation covering the period July 1997 to June 2000 and reflected the order in its financial statements. This final order was appealed to the Travis County District Court. In May 2003, the District Court upheld the PUCT's final order. That order is currently on appeal to the Third Court of Appeals.

TCC Fuel Reconciliation

In December 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the 2004 true-up proceeding. This reconciliation covers the period of July 1998 through December 2001. At December 31, 2001, the over-recovery balance for TCC was $63.5 million including interest. During the reconciliation period, TCC incurred $1.6 billion of eligible fuel and fuel-related expenses.

Based on the PUCT ruling in the TNC proceeding relating to similar issues, TCC established a reserve for potential adverse rulings of $81 million during 2003. In July 2003, the ALJ requested that additional information be provided in the TCC fuel reconciliation related to the impact of the TNC orders, referenced above, on TCC. On February 3, 2004, the ALJ issued a PFD recommending that the PUCT disallow $140 million in eligible fuel costs including some new items not considered in the TNC case, and other items considered but not disallowed in the TNC ruling. At this time, management is unable to predict the outcome of this proceeding. An adverse ruling from the PUCT, disallowing amounts in excess of the established reserve could have a material impact on future results of operations, cash flows and financial condition. Additional information regarding the 2004 true-up proceeding for TCC can be found in Note 6 "Customer Choice and Industry Restructuring."

SWEPCo Texas Fuel Reconciliation

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in SPP. This reconciliation covers the period of January 2000 through December 2002. At December 31, 2002, SWEPCo's filing included a $2 million deferred over-recovery balance including interest. During the reconciliation period, SWEPCo incurred $435 million of Texas retail eligible fuel expense. In November 2003, intervenors and the PUCT Staff recommended fuel cost disallowances of more than $30 million. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation. The settlement provides for a disallowance in fuel costs of $8 million which was recorded in December 2003. In addition, the settlement provides for the deferral as a regulatory asset of costs of a new lignite mining agreement in excess of a specified benchmark for lignite at SWEPCo's Dolet Hills Plant. The settlement provides for recovery of the deferred costs over a period ending in April 2011 as cost savings are realized under the new mining agreement. The settlement also will allow future recovery of litigation costs associated with the termination of a previous lignite mining agreement if future costs savings are adequate. The settlement will be filed with the PUCT for approval.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel (OPC) and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. On June 25, 2003, the District Court ruled in both appeals. The Court ruled in the Mutual Energy WTU case that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, and that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The Court upheld the initial PTB orders on all other issues. In the Mutual Energy CPL proceeding, the Court ruled that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately $2.7 million for Mutual Energy WTU. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. The District Court decision was appealed to the Third Court of Appeals by Mutual Energy CPL, Mutual Energy WTU and other parties. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the District Court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in 2002 and 2003 resulting in an adverse effect on future results of operations and cash flows.

Unbundled Cost of Service (UCOS) Appeal

The UCOS proceeding established the regulated wires rates to be effective when retail electric competition began. TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. Regulated delivery charges include the retail transmission and distribution charge and, among other items, a nuclear decommissioning fund charge, a municipal franchise fee, a system benefit fund fee, a transition charge associated with securitization of regulatory assets and a credit for excess earnings. Certain rulings of the PUCT in the UCOS proceeding, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, regulatory treatment of nuclear insurance and distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to non-bypassable transmission and distribution rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. The distribution rate credit began in January 2002. This decision could potentially affect the PTB rates charged by Mutual Energy CPL and could result in a refund to certain of its customers. Mutual Energy CPL was a subsidiary of AEP until December 23, 2002 when it was sold. Management estimates that the effect of a decision to reduce the PTB rates for the period prior to the sale is approximately $11 million pre-tax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

TCC Rate Case

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCC's proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%. On February 9, 2004, eight intervening parties filed testimony recommending reductions to TCC's requested $67 million rate increase. The recommendations range from a decrease in existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. The PUCT Staff filed testimony, on February 17, 2004, recommending reductions to TCC's request of approximately $51 million. TCC's rebuttal testimony was filed on February 26, 2004. Hearings are scheduled for March 2004 with a PUCT decision expected in May 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates or its impact on TCC's results of operations, cash flows and financial condition.

Louisiana Fuel Audit

The LPSC is performing an audit of SWEPCo's historical fuel costs. In addition, five SWEPCo customers filed a suit in the Caddo Parish District Court in January 2003 and filed a complaint with the LPSC. The customers claim that SWEPCo has over charged them for fuel costs since 1975. The LPSC consolidated the customer complaint and audit. In January 2004, a procedural schedule was issued requiring LPSC Staff and intervenor testimony to be filed in June 2004 and scheduling hearings for October 2004. Management believes that SWEPCo's fuel costs were proper and those costs incurred prior to 1999 have been approved by the LPSC. Management is unable to predict the outcome of these proceedings. If the actions of the LPSC or the Court result in a material disallowance of recovery of SWEPCo's fuel costs from customers, it could have an adverse impact on results of operations and cash flows.

Louisiana Compliance Filing

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of their order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid 2005. The filing indicates that SWEPCo's current rates should not be reduced. In 2004 the LPSC required SWEPCo to file updated financial information with a test year ending December 31, 2003 before April 16, 2004. If, after review of the updated information, the LPSC disagrees with our conclusion, they could order SWEPCo to file all documents for a full cost of service revenue requirement review in order to determine whether SWEPCo's capped rates should be reduced which would adversely impact results of operations and cash flows.

FERC Wholesale Fuel Complaints

Certain TNC wholesale customers filed a complaint with FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs since 1997.

Negotiations to settle the complaint and update the contracts resulted in new contracts. The FERC approved an offer of settlement regarding the fuel complaint and new contracts at market prices in December 2003. Since TNC had recorded a provision for refund in 2002, the effect of the settlement was a $4 million favorable adjustment recorded in December 2003.

Environmental Surcharge Filing

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately $21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant. See NOx Reductions in Note 7.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million became effective in May 2003 and an additional $16.2 million became effective in July 2003. The recovery of such amounts is intended to offset KPCo's cost of compliance with the Clean Air Act.

PSO Rate Review

In February 2003, the Director of the OCC filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003, PSO filed financial information and supporting testimony in response to the OCC's requirements. PSO's response indicates that its annual revenues are $36 million less than costs. As a result, PSO is seeking OCC approval to increase its base rates by that amount, which is a 3.6% increase over PSO's existing revenues. Hearings are scheduled for October 2004. Management is unable to predict the ultimate effect of this review on PSO's rates or its impact on PSO's results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power

PSO had a $44 million under-recovery of fuel costs resulting from a 2002 reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the OCC seeking recovery of the $44 million over an 18-month time period. In August 2003, the OCC Staff filed testimony recommending PSO be granted recovery of $42.4 million over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed its testimony in February 2004 and hearings will occur in June 2004. If the OCC determines as a result of the review that a portion of PSO's fuel and purchased power costs should not be recovered, there will be an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

Virginia Fuel Factor Filing

APCo filed with the Virginia SCC to reduce its fuel factor effective August 1, 2003. The requested fuel rate reduction was approved by the Virginia SCC and is effective for 17 months (August 1, 2003 to December 31, 2004) and is estimated to reduce revenues by $36 million during that period. This fuel factor adjustment will reduce cash flows without impacting results of operations as any over-recovery or under-recovery of fuel costs would be deferred as a regulatory liability or a regulatory asset.

FERC Long-term Contracts

In 2002, the FERC set for hearing complaints filed by certain wholesale customers located in Nevada and Washington that sought to break long-term contracts which the customers alleged were "high-priced." At issue were long-term contracts entered into during the California energy price spike in 2000 and 2001. The complaints alleged that AEP sold power at unjust and unreasonable prices.

In February 2003, AEP and one of the customers agreed to terminate their contract. The customer withdrew its FERC complaint and paid $59 million to AEP. As a result of the contract termination, AEP reversed $69 million of unrealized mark-to-market gains previously recorded, resulting in a $10 million pre-tax loss.

In December 2002, a FERC ALJ ruled in favor of AEP and dismissed a complaint filed by two Nevada utilities. In 2000 and 2001, we agreed to sell power to the utilities for future delivery. In 2001, the utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities had failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The utilities requested a rehearing which the FERC denied. The utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

RTO Formation/Integration Costs

With FERC approval, AEP East companies have been deferring costs incurred under FERC orders to form an RTO (the Alliance RTO) or join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both our Alliance formation costs and our PJM integration costs including the deferral of a carrying charge. The AEP East companies have deferred approximately $28 million of RTO formation and integration costs and related carrying charges through December 31, 2003. As a result of the subsequent delay in the integration of AEP's East transmission system into PJM, FERC declined to rule, in its July order, on our request to transfer the deferrals to regulatory assets, and to maintain the deferrals until such time as the costs can be recovered from all users of AEP's East transmission system. The AEP East companies will apply for permission to transfer the deferred formation/integration costs to a regulatory asset prior to integration with PJM. In August 2003, the Virginia SCC filed a request for rehearing of the July order, arguing that FERC's action was an infringement on state jurisdiction, and that FERC should not have treated Alliance RTO startup costs in the same manner as PJM integration costs. On October 22, 2003, FERC denied the rehearing request.

In its July 2003 order, FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the open access transmission tariff (OATT) to be charged by PJM. Management believes that the FERC will grant permission for the deferred RTO costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of AEP East companies' portion of the OATT at the time they join PJM. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo. APCo's Virginia retail base rates are capped with an opportunity for a one-time increase in non-generation rates after January 1, 2004. We intend to file an application with FERC seeking permission to delay the amortization of the deferred RTO formation/integration costs until they are recoverable from all users of the transmission system including retail customers. Management is unable to predict the timing of when AEP will join PJM and if upon joining PJM whether FERC will grant a delay of recovery until the rate caps and freezes end. If the AEP East companies do not obtain regulatory approval to join PJM, we are committed to reimburse PJM for certain project implementation costs (presently estimated at $24 million for the entire PJM integration project). Management intends to seek recovery of the deferred RTO formation/integration costs and project implementation cost reimbursements, if incurred. If the FERC ultimately decides not to approve a delay or the state commissions deny recovery, future results of operations and cash flows could be adversely affected.

In the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed with the Virginia SCC a cost/benefit study covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In August 2003, KPCo sought and was granted a rehearing to submit additional evidence. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately $13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. The order was based on PURPA 205(a), which allows FERC to exempt electric utilities from state law or regulation in certain circumstances. The FERC set for public hearing before an ALJ several issues. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the exceptions under PURPA apply. The FERC directed the ALJ to issue his initial decision by March 15, 2004.

FERC Order on Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the Midwest ISO to make compliance filings for their respective Open Access Transmission Tariffs to eliminate, by November 1, 2003, the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (RTO Footprint). In October 2003, the FERC postponed the November 1, 2003 deadline to eliminate T&O rates. The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs' revenue distribution protocols. The order provided that affected transmission owners could file to offset the elimination of these revenues by increasing rates or utilizing a transitional rate mechanism to recover lost revenues that result from the elimination of the T&O rates. The FERC also found that the T&O rates of some of the former Alliance RTO companies, including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the RTO Footprint. FERC initiated an investigation and hearing in regard to these rates. We made a filing with the FERC to support the justness and reasonableness of our rates. We also made a joint filing with unaffiliated utilities proposing a regional revenue replacement mechanism for the lost revenues, in the event that FERC eliminated all T&O rates for delivery points within the RTO Footprint. In orders issued in November 2003, the FERC dismissed the joint filing, but adopted a new regional rate design substantially in the form proposed in the joint filing. The orders directed each transmission provider to file compliance rates to eliminate T&O rates prospectively within the region and simultaneously implement new seams elimination cost allocation (SECA) rates to mitigate the lost revenues for a two-year transition period beginning April 1, 2004. The FERC did not indicate the recovery method for the revenues after the two-year period. As required by the FERC, we filed compliance tariff changes in January 2004 to eliminate the T&O charges within the RTO Footprint. The SECA rate issues that remain unresolved have been set before an ALJ for settlement procedures, and the effective date of the T&O rate elimination and SECA rates were delayed until May 1, 2004. The November orders have been appealed by a number of parties. The AEP East companies received approximately $150 million of T&O rate revenues from transactions delivering energy to customers in the RTO Footprint for the twelve months ended June 30, 2003. At this time, management is unable to predict whether the new SECA rates will fully compensate the AEP East companies for their lost T&O rate revenues and, consequently, their impact on our future results of operations, cash flows and financial condition.

Indiana Fuel Order

On July 17, 2003, I&M filed a fuel adjustment clause application requesting authorization to implement the fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant Outage) for electric service for the billing months of October 2003 through February 2004, and for approval of a new fuel cost adjustment credit for electric service to be applicable during the March 2004 billing month.

On August 27, 2003, the IURC issued an order approving the requested fixed fuel adjustment charge for October 2003 through February 2004. The order further stated that certain parties must negotiate the appropriate action on fuel to commence on March 1, 2004. Such negotiations are ongoing. The IURC deferred ruling on the March 2004 factor until after January 1, 2004.

Michigan 2004 Fuel Recovery Plan

The MPSC's December 16, 1999 order approved a Settlement Agreement regarding the extended outage of the Cook Plant and fixed I&M Power Supply Cost Recovery (PSCR) factors for the St. Joseph and Three Rivers rate areas through December 2003. In accordance with the settlement, PSCR Plan cases were not required to be filed through the 2003 plan year. As required, I&M filed its 2004 PSCR Plan with the MPSC on September 30, 2003 seeking new fuel and power supply recovery factors to be effective in 2004. The case has been scheduled for hearing. As allowed by Michigan law, the proposed factors were effective on January 1, 2004, subject to review and possible adjustment based on the results of the hearing.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2003	December 31, 2002	Future Recovery/ Refund Period
	(in millions)		
Regulatory Assets:			
Income Tax-related Regulatory Assets, Net	$728	$639	Various Periods (a)
Transition Regulatory Assets	529	743	Up to 5 Years (a)
Regulatory Assets Designated for Securitization	1,253	331	(b)
Texas Wholesale Capacity Auction True-Up	480	262	(c)
Unamortized Loss on Reacquired Debt	116	83	Up to 40 Years (d)
Cook Nuclear Plant Restart Costs	-	40	N/A
Cook Nuclear Plant Refueling Outage Levelization	57	30	(e)
Deferred Fuel Costs	24	121	1 Year (a)
CSW Merger Costs	23	32	Up to 5 Years (a)
Deferred Fuel Costs (TNC)	27	27	(c)
DOE Decontamination and Decommissioning Assessment	21	26	Up to 5 Years (a)
Other	290	354	Various Periods (f)
Total Regulatory Assets	$3,548	$2,688	
Regulatory Liabilities:			
Asset Removal Costs	$1,233	$-	(h)
Deferred Investment Tax Credits	422	455	Up to 26 Years (a)
Excess ARO for Nuclear Decommissioning Liability	216	-	(g)
Deferred Over-Recovered Fuel Costs (TCC)	69	69	(c)
Deferred Over-Recovered Fuel Costs	63	21	(a)
Texas Retail Clawback	57	66	(c)
Other	199	328	Various Periods (f)
Total Regulatory Liabilities	$2,259	$939	

(a) Amount does not earn a return.
(b) Will be included in TCC's PUCT 2004 true-up proceeding and is designated for possible securitization during 2005.
(c) Amount will be included in TCC's and TNC's 2004 true-up proceedings for future recovery/payment over a time period to be determined in a future PUCT proceeding.
(d) Amount effectively earns a return.
(e) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage and does not earn a return.
(f) These regulatory assets and liabilities include items both earning and not earning a return.
(g) Amounts are accrued monthly and will be paid when the nuclear plant is decommissioned. This also earns a return.
(h) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

Texas Restructuring Related Regulatory Assets and Liabilities

Regulatory Assets Designated for Securitization, Texas Wholesale Capacity Auction True-up regulatory assets, Deferred Over-Recovered Fuel Costs and Texas Retail Clawback regulatory liabilities are not being currently recovered from or returned to ratepayers. Management believes that the laws and regulations, established in Texas for industry restructuring, provide for the recovery from ratepayers of these net amounts. See Note 6 for a complete discussion of our plans to recover these regulatory assets, net of regulatory liabilities.

Nuclear Plant Restart

I&M completed the restart of both units of the Cook Plant in 2000. Settlement agreements in the Indiana and Michigan retail jurisdictions that addressed recovery of Cook Plant related outage restart costs were approved in 1999 by the IURC and MPSC.

The amount of deferrals amortized to other O&M expenses were $40 million in 2003, 2002 and 2001. Also pursuant to the settlement agreements, accrued fuel-related revenues of approximately $37 million in 2003 and $38 million in 2002 and 2001 were amortized as a reduction of revenues.

The amortization of O&M costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected results of operations through December 31, 2003 when the amortization period ended.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. The following table summarizes significant merger-related agreements:

Summary of key provisions of Merger Rate Agreements:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	$221 million rate reduction over 6 years. No base rate increases for 3 years post merger.
Indiana – I&M	$67 million rate reduction over 8 years. Extension of base rate freeze until January 1, 2005. Requires additional annual deposits of $6 million to the nuclear decommissioning trust fund for the years 2001 through 2003.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years. Extension of base rate freeze until January 1, 2005.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years. No base rate increases for 3 years post merger.
Oklahoma – PSO	Rate reductions of approximately $28 million over 5 years. No base rate increase before January 1, 2003.
Arkansas – SWEPCo	Rate reductions of $6 million over 5 years. No base rate increase before June 15, 2003
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years. Base rate cap until June 2005.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

See Note 7, "Commitments and Contingencies" for information on a court decision concerning the merger.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

Prior to 2003, retail customer choice began in four of the eleven state retail jurisdictions (Michigan, Ohio, Texas and Virginia) in which the AEP domestic electric utility companies operate. The following paragraphs discuss significant events related to customer choice and industry restructuring.

OHIO RESTRUCTURING

On June 27, 2002, the Ohio Consumers' Counsel, Industrial Energy Users–Ohio and American Municipal Power–Ohio filed a complaint with the PUCO alleging that CSPCo and OPCo have violated the PUCO's orders regarding implementation of their transition plan and violated the applicable law by failing to participate in an RTO.

The complainants seek, among other relief, an order from the PUCO:

- suspending collection of transition charges by CSPCo and OPCo until transfer of control of their transmission assets has occurred
- requiring the pricing of standard offer electric generation effective January 1, 2006 at the market price used by CSPCo and OPCo in their 1999 transition plan filings to estimate transition costs and
- imposing a $25,000 per company forfeiture for each day AEP fails to comply with its commitment to transfer control of transmission assets to an RTO

Due to FERC, state legislative and regulatory developments, CSPCo and OPCo have been delayed in the implementation of their RTO participation plans. We continue to pursue integration of CSPCo, OPCo and other AEP East companies into PJM. In this regard, on December 19, 2002, CSPCo and OPCo filed an application with the PUCO for approval of the transfer of functional control over certain of their transmission facilities to PJM. In February 2003, the PUCO consolidated the June 2002 complaint with our December application. CSPCo's and OPCo's motion to dismiss the complaint has been denied by the PUCO and the PUCO affirmed that ruling in rehearing. All further action in the consolidated case has been stayed "until more clarity is achieved regarding matters pending at the FERC and elsewhere." Management is currently unable to predict the timing of the AEP East companies' (including CSPCo and OPCo) participation in PJM, the outcome of these proceedings before the PUCO or their impact on results of operations and cash flows.

In October 2002, the PUCO initiated an investigation of the financial condition of Ohio's regulated public utilities. The PUCO's goal is to identify measures available to the PUCO to ensure that the regulated operations of Ohio's public utilities are not impacted by adverse financial consequences of parent or affiliate company unregulated operations and take appropriate corrective action, if necessary. The utilities and other interested parties were requested to provide comments and suggestions by November 12, 2002, with reply comments by November 22, 2002, on the type of information necessary to accomplish the stated goals, the means to gather the required information from the public utilities and potential courses of action that the PUCO could take. In January 2004, the PUCO staff issued a report recommending that the PUCO seek more authority from the Ohio Legislature on this issue. The PUCO has taken no further action in this proceeding. Management is unable to predict the outcome of the PUCO's investigation or its impact on results of operations, cash flows and business practices, if any.

On March 20, 2003, the PUCO commenced a statutorily required investigation concerning the desirability, feasibility and timing of declaring retail ancillary, metering or billing and collection service, supplied to customers within the certified territories of electric utilities, a competitive retail electric service. The PUCO sent out a list of questions and set June 6, 2003 and July 7, 2003 as the dates for initial responses and replies, respectively. CSPCo and OPCo filed comments and responses in compliance with the PUCO's schedule. Management is unable to predict the timing or the outcome of this proceeding or its impact on results of operations or cash flows.

The Ohio Act provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005. The PUCO may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utility's certified territory or that there is a twenty percent switching rate of the incumbent utility's load by customer class. Following the MDP, retail customers will receive distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates. On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rule provides for a Market Based Standard Service Offer which would be a variable rate based on a transparent forward market, daily market, and/or hourly market prices. The rule also requires a fixed-rate Competitive Bidding Process for residential and small nonresidential customers and permits a fixed-rate Competitive Bidding Process for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the Market Based Standard Service Offer or the Competitive Bidding Process. Customers who make no choice will be served pursuant to the Competitive Bidding Process.

On February 9, 2004, CSPCo and OPCo filed their rate stabilization plan with the PUCO addressing rates following the end of the MDP, which ends December 31, 2005. If approved by the PUCO, rates would be established pursuant to the plan for the period from January 1, 2006 through December 31, 2008 instead of the rates discussed in the previous paragraph. The plan is intended to provide rate stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. The plan includes annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo), and the opportunity for additional generation-related increases upon PUCO review and approval. For residential customers, however, if the temporary 5% generation rate discount provided by the Ohio Act were eliminated on June 30, 2004, the fixed increases would be 1.6% for CSPCo and 5.7% for OPCo. The generation-related increases under the plan would be subject to caps. The plan would maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level effective on December 31, 2005. Such rates could be adjusted for specified reasons through a PUCO filing. Transmission charges can be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion, and ancillary services. The plan also provides for continued recovery of transition regulatory assets and deferral of regulatory assets in 2004 and 2005 for RTO costs and carrying costs on required environmental expenditures. A procedural schedule has not been established for this filing. Management cannot predict whether the plan will be approved as submitted, modified by the PUCO, or its impacts on results of operation and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, we are deferring customer choice implementation costs and related carrying costs that are in excess of $40 million. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. The February 2004 filing provides for the continued deferral of customer choice implementation costs during the rate stabilization plan period. At December 31, 2003, we have incurred $66 million and deferred $26 million of such costs. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. If the rate stabilization plan is approved, it would defer recovery of these amounts until after the end of the rate stabilization period. Management believes that the customer choice implementation costs were prudently incurred and the deferred amounts should be recoverable in future rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING

Texas Legislation enacted in 1999 provided the framework and timetable to allow retail electricity competition for all customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007.

The Texas Legislation, among other things:

- provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility;
- provides for an earnings test for each of the years 1999 through 2001 and;
- provides for a 2004 true-up proceeding. See 2004 true-up proceeding discussion below.

The Texas Legislation required vertically integrated utilities to legally separate their generation and retail-related assets from their transmission and distribution-related assets. Prior to 2002, TCC and TNC functionally separated their operations to comply with the Texas Legislation requirements. AEP formed new subsidiaries to act as affiliated REPs for TCC and TNC effective January 1, 2002 (the start date of retail competition). In December 2002, AEP sold the affiliated REPs to an unaffiliated company.

In 1999, TCC filed with the PUCT to securitize $1.27 billion of its retail generation-related regulatory assets and $47 million in other qualified restructuring costs. The PUCT authorized the issuance of up to $797 million of securitization bonds ($949 million of generation-related regulatory assets and $33 million of qualified refinancing costs offset by $185 million of customer benefits for accumulated deferred income taxes). TCC issued its securitization bonds in February 2002. The amount not approved for securitization will be included in regulatory assets/stranded costs in TCC's 2004 true-up proceeding.

TEXAS 2004 TRUE-UP PROCEEDING

A 2004 true-up proceeding will determine the amount and recovery of:
- net stranded generating plant costs and generation-related regulatory assets (stranded costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's ECOM model for 2002 and 2003 (wholesale capacity auction true-up),
- final approved deferred fuel balance,
- unrefunded accumulated excess earnings,
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback) and
- other restructuring true-up items

The PUCT adopted a rule in 2003 regarding the timing of the 2004 true-up proceedings scheduling TNC's filing in May 2004 and TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later.

Stranded Costs and Generation-Related Regulatory Assets

Restructuring legislation required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. TCC is the only AEP subsidiary that has stranded costs under the Texas Legislation. We have elected to use the sale of assets method to determine the market value of all of our generation assets for stranded cost purposes. When completed, the sale of our generation assets will substantially complete the required separation of generation assets from transmission and distribution assets. For purposes of the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

In December 2002, TCC filed a plan of divestiture with the PUCT seeking approval of a sales process for all of its generating facilities. In March 2003, the PUCT dismissed TCC's divestiture filing, determining that it was more appropriate to address allowable valuation methods for the nuclear asset in a rulemaking proceeding. The PUCT approved a rule, in May 2003, which allows the market value obtained by selling nuclear assets to be used in determining stranded costs. Although the PUCT declined to review TCC's proposed sale of assets process, the PUCT has hired a consultant to advise TCC during the sale of the generation assets. TCC's sale of its generating assets will be subject to a review in the 2004 true-up proceeding.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCC's generating capacity in Texas. In order to sell these assets, we anticipate retiring TCC's first mortgage bonds by making open market purchases or defeasing the bonds. Bids were received for all of TCC's generating plants. In January 2004, TCC agreed to sell its 7.8% ownership interest in the Oklaunion Power Station to an unaffiliated third party for $43 million. The sale of TCC's remaining generation is pending. Additional regulatory approvals will be required to complete the sale of the generation assets, including NRC approval of the transfer of our interest in STP.

In the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized and reduced by mitigation including unrefunded excess earnings, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

After the 2004 true-up proceeding, TCC may seek to issue securitization revenue bonds for its stranded costs and recover the costs of the securitization bonds through transmission and distribution rates. Based upon the Oklaunion sale and the bid information for the remaining generation, we recorded an impairment of generating assets of $938 million in December 2003 as a regulatory asset (see Note 10). The recovery of the regulatory asset will be subject to review and approval by the PUCT as a stranded cost in the 2004 true-up proceeding.

Wholesale Capacity Auction True-up

Texas Legislation also requires that electric utilities and their affiliated power generation companies (PGC) offer for sale at auction, in 2002 and 2003 and after, at least 15% of the PGC's Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation. Actual market power prices received in the state mandated auctions will be used to calculate the wholesale capacity auction true-up adjustment for TCC for the 2004 true-up proceeding.

TCC recorded a $480 million regulatory asset and related revenues which represent the quantifiable amount of the wholesale capacity auction true-up for the years 2002 and 2003. In TCC's UCOS proceeding, the PUCT estimated that TCC had negative stranded costs. In its true-up rule, the PUCT determined that the wholesale capacity auction true-up proceeds should be offset against negative stranded costs. However, in March 2003, the Texas Court of Appeals ruled that under the restructuring legislation, other 2004 true-up items, including the wholesale capacity auction true-up regulatory asset, could be recovered regardless of the level of stranded costs.

In the fourth quarter of 2003, the PUCT approved a true-up filing package containing calculation instructions similar to the methodology employed by TCC to calculate the amount recorded for recovery under its wholesale capacity auction true-up. The PUCT will review the $480 million wholesale capacity regulatory asset for recovery as part of the 2004 true-up proceeding.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. In January 2004, the PUCT announced a final ruling in TNC's fuel reconciliation case that established TNC's unrecovered fuel balance, including interest for the ERCOT service territory, at $6.2 million. This balance will be included in TNC's 2004 true-up proceeding. TNC is waiting for a written order from the PUCT, after which it will request a rehearing.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery of fuel balance for inclusion in the 2004 true-up proceeding. In February 2004, an ALJ issued recommendations finding a $205 million over-recovery in this fuel proceeding. Management is unable to predict the amount of TCC's fuel over-recovery which will be included in its 2004 true-up proceeding.

See TCC Fuel Reconciliation and TNC Fuel Reconciliation in Note 4 "Rate Matters" for further discussion.

Unrefunded Excess Earnings

The Texas Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined for the three year period were $3 million for SWEPCo, $47 million for TCC and $19 million for TNC. TCC, TNC and SWEPCo challenged the PUCT's treatment of fuel-related deferred income taxes and appealed the PUCT's final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. The District Court's ruling was appealed to the Third Court of Appeals. In August 2003, the Third Court of Appeals reversed the PUCT order and the District Court's judgment. The PUCT's request for rehearing of the Appeals Court's decision was denied and the PUCT chose not to appeal the ruling any further. Appeal of the same issue from the PUCT's 2001 order is pending before the District Court. Since an expense and regulatory liability had been accrued in prior years in compliance with the PUCT orders, the companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Court's decision and credited amortization expense during the third quarter of 2003. Pre-tax amounts reversed by company were $5 million for TCC, $3 million for TNC and $1 million for SWEPCo.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order has no additional effect on reported net income but will reduce cash flows for the five-year refund period. The amount to be refunded is recorded as a regulatory liability. Management believes that TCC will have stranded costs and that it was inappropriate for the PUCT to order a refund prior to TCC's 2004 true-up proceeding. TCC appealed the PUCT's refund of excess earnings to the Travis County District Court. That court affirmed the PUCT's decision and further ordered that the refunds be provided to customers. TCC has appealed the decision to the Court of Appeals.

Retail Clawback

The Texas Legislation provides for the affiliated PTB REP serving residential and small commercial customers to refund to its T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. During 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. The PUCT approved TCC's and TNC's filings in December 2003. In 2002, AEP had accrued a regulatory liability of approximately $9 million for the small commercial retail clawback on its REP's books. When the PUCT certified that the REP's in TCC and TNC service territories had reached the 40% threshold, the regulatory liability was no longer required for the small commercial class and was reversed in December 2003. At December 31, 2003, the remaining retail clawback regulatory liability was $57 million.

When the 2004 true-up proceeding is completed, TCC intends to file to recover PUCT-approved stranded costs and other true-up amounts that are in excess of current securitized amounts, plus appropriate carrying charges and other true-up amounts, through non-bypassable competition transition charge in the regulated T&D rates. TCC may also seek to securitize certain of the approved stranded plant costs and regulatory assets that were not previously recovered through the non-bypassable transition charge. The annual costs of securitization are recovered through a non-bypassable rate surcharge collected by the T&D utility over the term of the securitization bonds.

In the event we are unable, after the 2004 true-up proceeding, to recover all or a portion of our stranded plant costs, generation-related regulatory assets, unrecovered fuel balances, wholesale capacity auction true-up regulatory assets, other restructuring true-up items and costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

MICHIGAN RESTRUCTURING

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total rates in Michigan remain unchanged and reflect cost of service. At December 31, 2003, none of I&M's customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Management has concluded that as of December 31, 2003 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

ARKANSAS RESTRUCTURING

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCo's Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999. The reapplication of SFAS 71 had an insignificant effect on results of operations and financial condition. As a result of reapplying SFAS 71, derivative contract gains/losses for transactions within AEP's traditional marketing area allocated to Arkansas will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized.

WEST VIRGINIA RESTRUCTURING

APCo reapplied SFAS 71 for its West Virginia (WV) jurisdiction in the first quarter of 2003 after new developments during the quarter prompted an analysis of the probability of restructuring becoming effective.

In 2000, the WVPSC issued an order approving an electricity restructuring plan, which the WV Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the WV legislature made tax law changes necessary to preserve the revenues of state and local governments.

In the 2001 and 2002 legislative sessions, the WV Legislature failed to enact the required legislation that would allow the WVPSC to implement the restructuring plan. Due to this lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring during the summer of 2002.

In the 2003 legislative session, the WV Legislature failed to enact the required tax legislation. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in WV. In March 2003, APCo's outside counsel advised us that restructuring in WV was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's WV generation. APCo has concluded that deregulation of the WV generation business is no longer probable and operations in WV meet the requirements to reapply SFAS 71.

Reapplying SFAS 71 in WV had an insignificant effect on results of operations and financial condition. As a result, derivative contract gains/losses related to transactions within AEP's traditional marketing area allocated to WV will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized. Positions outside AEP's traditional marketing area will continue to be marked-to-market.

7. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

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

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 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). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

On August 7, 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, an unaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not "routine" maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any non-routine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A remedy trial is scheduled for July 2004.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in our case also vary widely from plant to plant. Further, the Ohio Edison decision is limited to liability issues, and provides no insight as to the remedies that might ultimately be ordered by the Court.

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, an unaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that the Federal EPA bears the burden of proof on the issue of whether a practice is "routine maintenance, repair, or replacement" and on whether or not a "significant net emissions increase" results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is "routine within the relevant source category" in determining if it is "routine." Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA has requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for alleged Clean Air Act violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the Clean Air Act are unconstitutional.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which our subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in our case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in our case.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines "routine maintenance repair and replacement" to include "functionally equivalent equipment replacement." Under the new final rule, replacement of a component within an integrated industrial operation (defined as a "process unit") with a new component that is identical or functionally equivalent will be deemed to be a "routine replacement" if the replacement does not change any of the fundamental design parameters of the process unit, does not result in emissions in excess of any authorized limit, and does not cost more than twenty percent of the replacement cost of the process unit. The new rule is intended to have prospective effect, and will become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003 twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

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

In December 2000, Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the 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 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

NUCLEAR

Nuclear Plants

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement I&M and TCC are partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $10.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $20 million. TCC could be assessed $50 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited. Under an industry-wide program insuring workers at nuclear facilities, I&M and TCC are also obligated for assessments of up to $6 million and $2 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. I&M and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $43 million for I&M and $2 million for TCC which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed in 2004 with increases in required third party financial protection for nuclear incidents.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses 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 $226 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, 2003, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. In November 2003, I&M filed to extend the operating licenses of the two Cook Plant units for up to an additional 20 years. The review of the license extension application is expected to take at least two years. After expiration of the licenses, Cook Plant is expected to be decommissioned using the prompt decontamination and dismantlement (DECON) method. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs for Cook Plant ranges from $821 million to $1,080 million in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $27 million in 2003, 2002 and 2001.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the DECON method. TCC estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC 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 2003, 2002 and 2001, I&M deposited in its decommissioning trust an additional $12 million each year related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in Other Operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in Other Operation expense, interest income of the trusts are recorded in Nonoperating Income and interest expense of the trust funds are included in Interest Charges.

TCC's nuclear decommissioning trust asset and liability are included in held for sale amounts on the Consolidated Balance Sheets.

OPERATIONAL

Construction and Commitments

The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2004-2006 for consolidated domestic and foreign operations are estimated to be $5.8 billion including amounts for proposed environmental rules.

Our subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The longest contract extends to the year 2014. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain conditions.

The AEP System has unit contingent contracts to supply approximately 250 MW of capacity to unaffiliated entities through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

Potential Uninsured Losses

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

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. Juniper will own the Facility and lease it to AEP after construction is completed and we will sublease the Facility to The Dow Chemical Company (Dow).

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as non-conforming.

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

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately $17.5 million. TEM may also claim that we are not entitled to receive any termination value for the PPA.

See further discussion in Notes 10 and 16.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region."

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUCHA's single region requirement because it is now technically possible to centrally control the output of power plants across many states. In its ruling, the appeals court said that the SEC failed to support and explain its conclusions that the integration and single region requirements are satisfied.

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

Enron Bankruptcy

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In connection with the 2001 acquisition of HPL, we acquired exclusive rights to use and operate the underground Bammel gas storage facility pursuant to an agreement with BAM Lease Company, a now-bankrupt subsidiary of Enron. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years and includes the use of the Bammel storage facility and the appurtenant pipelines. We have engaged in discussions with Enron concerning the possible purchase of the Bammel storage facility and related assets, the possible resolution of outstanding issues between AEP and Enron relating to our acquisition of HPL and the possible resolution of outstanding energy trading issues. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. We are unable to predict whether these discussions will lead to an agreement on these subjects. In January 2004, AEP and its subsidiaries filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron does not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In February 2004 Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. Management is unable to predict the outcome of these proceedings or the impact on results of operations, cash flows or financial condition.

We also entered into an agreement with BAM Lease Company which grants HPL the exclusive right to use approximately 65 billion cubic feet of cushion gas required for the normal operation of the Bammel gas storage facility. The Bammel Gas Trust (owned by Enron and Bank of America (BOA)) purports to have a lien on 55 billion cubic feet of this cushion gas. These banks claim to have certain rights to the cushion gas in certain events of default. In connection with our acquisition of HPL, the banks and Enron entered into an agreement granting HPL's exclusive use of 65 billion cubic feet of cushion gas. Enron and the banks released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, HPL was informed by the banks of a purported default by Enron under the terms of the financing arrangement. In July 2002, the banks filed a lawsuit against HPL in the state court of Texas seeking a declaratory judgment that they have a valid and enforceable security interest in gas purportedly in the Bammel storage facility which would permit them to cause the withdrawal of up to 55 billion cubic feet of gas from the storage facility. In September 2002, HPL filed a general denial and certain counterclaims against the banks including that Enron was a necessary and indispensable party to the Texas state court proceeding initiated by BOA. HPL also filed a motion to dismiss, which was denied. In December 2003, the Texas state court granted partial summary judgment in favor of the banks. HPL appealed this decision. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows and financial condition.

In October 2003, AEP Energy Services Gas Holding Company filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. On January 8, 2004, this lawsuit was amended and seeks damages for BOA's breach of contract, negligent misrepresentation and fraud in connection with transactions surrounding our acquisition of HPL from Enron including entering into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangements with BOA and Enron. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. We will assert our right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

During 2002 and 2001, we expensed a total of $53 million ($34 million net of tax) for our estimated loss from the Enron bankruptcy. The amount expensed was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and the Bammel storage facility lease agreement and cushion gas agreement. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, lawsuits alleging securities law violations and seeking class action certification were filed in federal District Court, Columbus, Ohio against AEP, certain AEP executives, and in some of the lawsuits, members of the AEP Board of Directors and certain investment banking firms. The lawsuits claim that we failed to disclose that alleged "round trip" trades resulted in an overstatement of revenues, that we failed to disclose that our traders falsely reported energy prices to trade publications that published gas price indices and that we failed to disclose that we did not have in place sufficient management controls to prevent "round trip" trades or false reporting of energy prices. The plaintiffs seek recovery of an unstated amount of compensatory damages, attorney fees and costs. The Court has appointed a lead plaintiff who has filed a Consolidated Amended Complaint. We have filed a Motion to Dismiss the Consolidated Amended Complaint. The Motion has been briefed by the parties. Also, in the first quarter of 2003, a lawsuit making essentially the same allegations and demands was filed in state Common Pleas Court, Columbus, Ohio against AEP, certain executives, members of the Board of Directors and our independent auditor. We removed this case to federal District Court in Columbus and the Court has denied plaintiff's motion to remand the case to state court. We have moved to consolidate this case with the other pending cases. We intend to continue to vigorously defend against these actions.

In the fourth quarter of 2002, two shareholder derivative actions were filed in state court in Columbus, Ohio against AEP and its Board of Directors alleging a breach of fiduciary duty for failure to establish and maintain adequate internal controls over our gas trading operations. These cases have been stayed pending the outcome of our Motion to Dismiss the Consolidated Amended Complaint in the federal securities lawsuits. If these cases do proceed, we intend to vigorously defend against them. Also, in the fourth quarter of 2002 and the first quarter of 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions are pending in federal District Court, Columbus, Ohio. In these actions, the plaintiffs seek recovery of an unstated amount of compensatory damages, attorney fees and costs. We have filed a Motion to Dismiss these actions. The parties have fully briefed this Motion. We intend to continue to vigorously defend against these claims.

California Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County, California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. This case is in the initial pleading stage and all defendants have filed motions to dismiss. AEP has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. In November 2003, Texas-Ohio Energy, Inc. filed a lawsuit in the United States District Court for the Eastern District of California alleging that AEP and a large number of other energy companies conspired to manipulate natural gas prices in California in violation of federal and state antitrust and unfair competition laws. Certain of the other defendants in this case have filed a Notice of Potential Tag-Along Action with the Judicial Panel on Multi-District Litigation seeking to have this case transferred to the United States District Court for the District of Nevada where there are a number of other cases now pending that assert claims regarding the alleged manipulation of energy markets in California. None of the AEP companies is a party to these other pending cases. Once venue for the Texas-Ohio Energy, Inc. case is determined, we plan to move to dismiss the complaint and otherwise vigorously defend against these claims. In February 2004, two individuals on behalf of themselves and two businesses they own and another individual filed an action in state court in San Diego County, California against a large number of energy companies including AEPES. This action alleges violations of state antitrust and unfair competition laws based on alleged manipulation of gas price indices. This case is in the initial pleading states. We plan to vigorously defend against these claims.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. On December 5, 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. We plan to move to dismiss the complaint and otherwise vigorously defend against these claims.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against us and four AEP subsidiaries, certain unaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We intend to file a motion to dismiss the amended complaint and otherwise vigorously defend against the claims.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals and claimed that we owed approximately $34 million. In April 2003, we filed a lawsuit in federal District Court in Columbus, Ohio against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately $68 million. We are claiming that BOM owes us at least $45 million. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Arbitration of Williams Claim

In October 2002, we filed a demand for arbitration with the American Arbitration Association to initiate formal arbitration proceedings in a dispute with the Williams Companies (Williams). The proceeding resulted from Williams' repudiation of its obligations to provide physical power deliveries to AEP and Williams' failure to provide the monetary security required for natural gas deliveries by AEP. Consequently, both parties claimed default and terminated all outstanding natural gas and electric power trading deals among the various Williams and AEP affiliates. Williams claimed that we owed approximately $130 million in connection with the termination and liquidation of all trading deals. Williams and AEP settled the dispute and we paid $90 million to Williams in June 2003. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the resolution of this matter did not have a material impact on results of operations or financial condition.

Arbitration of PG&E Energy Trading, LLC Claim

In January 2003, PG&E Energy Trading, LLC (PGET) claimed approximately $22 million was owed by AEP in connection with the termination and liquidation of all trading deals. In February 2003, PGET initiated arbitration proceedings. In July 2003, AEP and PGET agreed to a settlement and we paid approximately $11 million to PGET. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the settlement payment did not have a material impact on results of operations, cash flows or financial condition.

Energy Market Investigation

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

In March 2003, we received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, we had received an informal data request from the SEC asking that we voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. We responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, it is not expected to have a material effect on results of operations due to a provision recorded in December 2003.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. We are responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

FERC Proposed Standard Market Design

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments that the FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until any potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

8. GUARANTEES

There are no liabilities recorded for guarantees entered into prior to December 31, 2002 in accordance with FIN 45. There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002. There is no collateral held in relation to any guarantees and there is no recourse to third parties in the event any guarantees are drawn unless specified below.

LETTERS OF CREDIT

We have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these LOCs were issued by us in the ordinary course of business. At December 31, 2003, the maximum future payments for all the LOCs are approximately $227 million with maturities ranging from January 2004 to January 2011. Included in these amounts is TCC's LOC of approximately $43 million with a maturity date of November 3, 2005. As the parent of all these subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

We have guaranteed 50% of the principal and interest payments as well as 100% of a Power Purchase Agreement (PPA) of Fort Lupton, an IPP of which we are a 50% owner. In the event Fort Lupton does not make the required debt payments, we have a maximum future payment exposure of approximately $7 million, which expires May 2008.

In the event Fort Lupton is unable to perform under its PPA agreement, we have a maximum future payment exposure of approximately $15 million, which expires June 2019.

We have guaranteed 50% of a security deposit for gas transmission as well as 50% of a Power Purchase Agreement (PPA) of Orange Cogeneration (Orange), an IPP of which we are a 50% owner. In the event Orange fails to make payments in accordance with agreements for gas transmission, we have a maximum future payment exposure of approximately $1 million, which expires June 2023. In the event Orange is unable to perform under its PPA agreement, we have a maximum future payment exposure of approximately $1 million, which expires June 2016.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

CSW Energy and CSW International

CSW Energy and CSW International have guaranteed 50% of the required debt service reserve of Sweeny Cogeneration (Sweeny), an IPP of which CSW Energy is a 50% owner. The guarantee was provided in lieu of Sweeny funding the debt reserve as a part of a financing. In the event that Sweeny does not make the required debt payments, CSW Energy and CSW International have a maximum future payment exposure of approximately $4 million, which expires June 2020.

AEP Utilities

AEP Utilities guaranteed 50% of the required debt service reserve for Polk Power Partners, an IPP of which CSW Energy owns 50%. In the event that Polk Power does not make the required debt payments, AEP Utilities has a maximum future payment exposure of approximately $5 million, which expires July 2010.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements,

SWEPCo's total future maximum payment exposure is approximately $58 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2003, the cost to reclaim the mine in 2035 is estimated to be approximately $36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

INDEMNIFICATIONS AND OTHER GUARANTEES

We entered into several types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. We cannot estimate the maximum potential exposure for any of these indemnifications entered into prior to December 31, 2002 due to the uncertainty of future events. In 2003 we entered into several sale agreements discussed in Note 10. These sale agreements include indemnifications with a maximum exposure of approximately $57 million. There are no material liabilities recorded for any indemnifications entered into during 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2003, the maximum potential loss for these lease agreements was approximately $28 million assuming the fair market value of the equipment is zero at the end of the lease term.

See Note 16 "Leases" for disclosure of lease residual value guarantees.

9. SUSTAINED EARNINGS IMPROVEMENT INITIATIVE

In response to difficult conditions in our business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

Termination benefits expense relating to 1,120 terminated employees totaling $75.4 million pre-tax was recorded in the fourth quarter of 2002. Of this amount, we paid $9.5 million to these terminated employees in the fourth quarter of 2002. No additional termination benefits expense related to the SEI initiative was recorded in 2003, and the remaining SEI related payments were made in 2003. The termination benefits expense is classified as Maintenance and Other Operation expense on our Consolidated Statements of Operations. We determined that the termination of the employees under our SEI initiative did not constitute a plan curtailment of any of our retirement benefit plans.

10. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

ACQUISITIONS

2002

Acquisition of Nordic Trading (Investments – UK Operations segment)

In January 2002 we acquired the trading operations, including key staff, of Enron's Norway and Sweden-based energy trading businesses (Nordic Trading). Results of operations are included in our Consolidated Statements of Operations from the date of acquisition. Subsequently in the fourth quarter of 2002, a decision was made to exit this non-core European trading business. The sale of Nordic Trading in the second quarter of 2003 is discussed in the "Dispositions" section of this note.

Acquisition of USTI (Investments – Other segment)

In January 2002, we acquired 100% of the stock of United Sciences Testing, Inc. (USTI) for $12.5 million. USTI provides equipment and services related to automated emission monitoring of combustion gases to both our affiliates and external customers. Results of operations are included in our Consolidated Statements of Operations from the date of acquisition.

2001

Houston Pipe Line Company (Investments – Gas Operations segment)

On June 1, 2001, through a wholly-owned subsidiary, we purchased Houston Pipe Line Company and Lodisco LLC for $727 million from Enron. The acquired assets include 4,200 miles of gas pipeline, a 30-year prepaid lease of a gas storage facility and certain gas marketing contracts. The purchase method of accounting was used to record the acquisition. During 2003 we recorded impairment and other losses for HPL and related gas operations of $315 million ($228 million net of tax).

U.K. Generation Plants (Investments – UK Operations segment)

In December 2001, we acquired 4,000 megawatts of coal-fired generation from Fiddler's Ferry, a four-unit, 2,000 MW station on the River Mersey in northwest England, and Ferrybridge, a four-unit, 2,000 MW station on the River Aire in northeast England and related coal stocks. These assets were acquired for a cash payment of $942.3 million and the assumption of certain liabilities. During 2003 these assets became held-for-sale and we reported the operations as discontinued. See U.K. Generation Plants in the "Discontinued Operations" section of this note for further information.

Other Acquisitions (Various segments)

We also purchased the following assets or acquired the following businesses from July 2001 through December 2001:

- Dolet Hills mining operations were purchased by SWEPCo, an AEP subsidiary, and SWEPCo also assumed the existing mine reclamation liabilities at its jointly owned lignite reserves in Louisiana.
- Quaker Coal Company as part of a bankruptcy proceeding settlement was acquired, including certain liabilities.

The acquisition includes property, coal reserves, mining operations and royalty interests in Colorado, Kentucky, Ohio, Pennsylvania and West Virginia. We continue to operate the mines and facilities. See AEP Coal in the "Assets Held for Sale" section of this note for further information on our decision to dispose of this investment.

- MEMCO Barge Line was acquired adding 1,200 hopper barges and 30 towboats to AEP's existing barging fleet. MEMCO added major barging operations on the Mississippi and Ohio rivers to AEP's barging operations on the Ohio and Kanawha rivers.
- A 20% equity interest in Caiua, a Brazilian electric operating company which is a subsidiary of Vale was acquired by converting a total of $66 million on an existing loan and accrued interest on that loan into Caiua equity. See Grupo Rede Investment in the "Dispositions" section of this note for further information.
- Indian Mesa Wind Project (referred to as "Desert Sky") consisting of 160 MW of wind generation located near Fort Stockton, Texas was purchased.
- Enron's London-based international coal trading group was acquired by purchasing existing contracts and hiring key staff.

Management recorded the assets acquired and liabilities assumed at their estimated fair values based on currently available information and on current assumptions as to future operations.

DISPOSITIONS

2003

C3 Communications (Investments – Other segment)

In February 2003, C3 Communications sold the majority of its assets for a sales price of $7.25 million. We provided for an $82 million pre-tax ($53 million after-tax) asset impairment in December 2002 and the effect of the sale on 2003 results of operations was not significant. The impairment is classified in Asset Impairments and Other Related Changes in our Consolidated Statements of Operations. See "Assets Held for Sale" section of this note for information on assets and liabilities held for sale at December 31, 2002 related to our "telecommunications" businesses.

Mutual Energy Companies (Utility Operations segment)

On December 23, 2002 we sold the general partner interests and the limited partner interests in Mutual Energy CPL L.P. and Mutual Energy WTU L.P. for a base purchase price paid in cash at closing and certain additional payments, including a net working capital payment. The buyer paid a base purchase price of $145.5 million which was based on a fair market value per customer established by an independent appraiser and an agreed customer count. We recorded a net gain totaling $83.7 million after-tax ($129 million pre-tax) in Other Income during 2002. We provided the buyer with a power supply contract for the two REPs and back-office services related to these customers for a two-year period. In addition, we retained the right to share in earnings from the two REPs above a threshold amount through 2006 in the event the Texas retail market develops increased earnings opportunities. No revenue was recorded in 2003 related to these sharing agreements. Under the Texas Legislation, REPs are subject to a clawback liability if customer change does not attain thresholds required by the legislation. We are responsible for a portion of such liability, if any, for the period we operated the REPs in the Texas competitive retail market (January 1, 2002 through December 23, 2002). In addition, we retained responsibility for regulatory obligations arising out of operations before closing. Our wholly-owned subsidiary Mutual Energy Service Company LLC (MESC) received an up-front payment of approximately $30 million from the buyer associated with the back-office service agreement, and MESC deferred its right to receive payment of an additional amount of approximately $9 million to secure certain contingent obligations. These prepaid service revenues were deferred on the books of MESC as of December 31, 2002 and are being amortized over the two-year term of the back office service agreement.

In February 2003, we completed the sale of MESC for $30.4 million dollars and realized a pre-tax gain of approximately $39 million, which included the recognition of the remaining balance of the original $30 million prepayment ($27 million), as no further service obligations existed for MESC.

Water Heater Assets (Utility Operations segment)

We sold our water heater rental program for $38 million and recorded a pre-tax loss of $3.9 million in the first quarter of 2003 based upon final terms of the sale agreement. We had provided for a $7.1 million pre-tax charge in the fourth quarter 2002 based on an estimated sales price ($3.2 million asset impairment charge and $3.9 million lease prepayment penalty). The impairment loss is included in Investment Value Losses in our Consolidated Statements of Operations. We operated a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale. See the "Assets Held for Sale" section of this Note for assets and liabilities held for sale as of December 31, 2002.

AEP Gas Power Systems (Investments – Other segment)

In 2001, we acquired a 75% interest in a startup company, seeking to develop low-cost peaking generator sets powered by surplus jet turbine engines. In January 2003, AEP Gas Power Systems, LLC sold its assets. We recognized a goodwill impairment loss of $12.3 million pre-tax in the first quarter of 2002 due to technological and operational problems (also see Note 3). The impairment loss was recorded in Investment Value Losses on our Consolidated Statements of Operations. The fair values of the remaining assets and liabilities as of December 31, 2002 were excluded from held for sale on our Consolidated Balance Sheets as the impact was not significant. The effect of the asset sale on the first quarter 2003 results of operations was not significant.

Newgulf Facility (Investments – Other segment)

In 1995, we purchased an 85 MW gas-fired peaking electrical generation facility located near Newgulf, Texas (Newgulf). In October 2002, we began negotiations with a likely buyer of the facility. We estimated a pre-tax loss on sale of $11.8 million based on the indicative bid. This loss was recorded as Asset Impairments and Other Related Charges on our Consolidated Statements of Operations during the fourth quarter 2002. Newgulf's Property, Plant and Equipment, net of accumulated depreciation, was classified on our Consolidated Balance Sheets as held for sale at December 31, 2002. During the second quarter of 2003 we completed the sale of Newgulf and the impact on earnings in 2003 was not significant.

Nordic Trading (Investments – UK Operations segment)

In October 2002 we announced that our ongoing energy trading operations would be centered around our generation assets. As a result, we took steps to exit our coal, gas and electricity trading activities in Europe, except for those activities predominantly related to our U.K. generation operations. The Nordic Trading business acquired earlier in 2002 was made available for sale to potential buyers later in 2002. The estimated pre-tax loss on disposal recorded in 2002 of $5.3 million, consisted of impairment of goodwill of $4.0 million and impairment of assets of $1.3 million. The estimated loss of $5.3 million is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. Management's determination of a zero fair value was based on discussions with a potential buyer. The assets and liabilities of Nordic Trading have been classified on our Consolidated Balance Sheets as held for sale at December 31, 2002. The transfer of the Nordic Trading business, including the trading portfolio, to new owners was completed during the second quarter of 2003 and the impact on earnings during the second quarter of 2003 was not significant.

Eastex (Investments – Other segment)

In 1998, we began construction of a natural gas-fired cogeneration facility (Eastex) located near Longview, Texas and commercial operations commenced in December 2001. In June 2002, we requested that the FERC allow us to modify the FERC Merger Order and substitute Eastex as a required divestiture under the order, due to the fact that the agreed upon market-power related divestiture of a plant in Oklahoma was no longer feasible. The FERC approved the request at the end of September 2002. Subsequently, in the fourth quarter of 2002, we solicited bids for the sale of Eastex and several interested buyers were identified by December 2002. The estimated pre-tax loss on sale of $218.7 million pre-tax ($142 million after-tax), which was based on the estimated fair value of the facility and indicative bids by interested buyers, was recorded in Discontinued Operations in our Consolidated Statements of Operations during the fourth quarter 2002.

We completed the sale of Eastex during the third quarter of 2003 and the effect of the sale on third quarter 2003 results of operations was not significant. The results of operations of Eastex have been reclassified as Discontinued Operations in accordance with SFAS 144 for all years presented. The assets and liabilities of Eastex were reclassified on the Consolidated Balance Sheets from Assets Held for Sale and Liabilities Held for Sale to Discontinued Operations at December 31, 2002. See "Discontinued Operations" section of this note for additional information.

Grupo Rede Investment (Investments – Other segment)

In December 2002, we recorded an other than temporary impairment totaling $141.0 million ($217.0 million net of federal income tax benefit of $76.0 million) of our 44% equity investment in Vale and our 20% equity interest in Caiua, both Brazilian electric operating companies (referred to as Grupo Rede). This amount is included in Investment Value Losses on our Consolidated Statements of Operations.

In December 2003 we transferred our share and investment in Vale to Grupo Rede for $1 million. The effect of the transfer on fourth quarter results of operations was not significant.

Excess Equipment (Investments – Other segment)

In November 2002, as a result of a cancelled development project, we obtained title to a surplus gas turbine generator. We had been unsuccessful in finding potential buyers of the unit due to an over-supply of generation equipment available for sale during 2002. An estimated pre-tax loss on disposal of $23.9 million was recorded in December 2002, based on market prices of similar equipment. The loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The Other asset of $12 million in 2002 was classified on our Consolidated Balance Sheets as held for sale at December 31, 2002.

We completed the sale of the surplus gas turbine generator in November 2003. The proceeds from the sale were $8.7 million. A pre-tax loss of $1.8 million was recorded in the fourth quarter of 2003.

Ft. Davis Wind Farm (Investments – Other segment)

In the 1990's, we developed a 6 MW facility wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002 our engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility is expected to be completed during 2004. An estimated pre-tax loss on abandonment of $4.7 million was recorded in December 2002. The loss was recorded in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

<u>2002</u>

SEEBOARD (Investments – Other segment)

On June 18, 2002, through a wholly-owned subsidiary, we entered into an agreement, subject to European Union (EU) approval, to sell our consolidated subsidiary SEEBOARD, a U.K. electricity supply and distribution company. EU approval was received July 25, 2002 and the sale was completed on July 29, 2002. We received approximately $941 million in net cash from the sale, subject to a working capital true up, and the buyer assumed SEEBOARD debt of approximately $1.12 billion, resulting in a net loss of $345 million at June 30, 2002. The results of operations of SEEBOARD have been classified as Discontinued Operations for all years presented. A net loss of $22 million pre-tax ($14 million after-tax) was classified as Discontinued Operations in the second quarter of 2002. The remaining $323 million of the net loss has been classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see Notes 2 and 3) and has been reported as a Cumulative Effect of Accounting Change retroactive to January 1, 2002. A $59 million pre-tax ($38 million after-tax) reduction of the net loss was recognized in the second half of 2002 to reflect changes in exchange rates to closing, settlement of working capital true-up and selling expenses. The net total loss recognized on the disposal of SEEBOARD was $286 million. Proceeds from the sale of SEEBOARD were used to pay down bank facilities and short-term debt. See "Discontinued Operations" section for the total revenues and pretax profit (loss) of the discontinued operations of SEEBOARD.

CitiPower (Investments – Other segment)

On July 19, 2002, through a wholly owned subsidiary, we entered into an agreement to sell CitiPower, a retail electricity and gas supply and distribution subsidiary in Australia. We completed the sale on August 30, 2002 and received net cash of approximately $175 million and the buyer assumed CitiPower debt of approximately $674 million. We recorded a pre-tax charge totaling $192 million ($125 million after-tax) as of June 30, 2002. The charge included a pre-tax impairment loss of $151 million ($98 million after-tax) on the remaining carrying value of an intangible asset related to a distribution license for CitiPower. The remaining $41 million pre-tax ($27 million after-tax) of net loss was classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see Notes 2 and 3) and was recorded as a Cumulative Effect of Accounting Change retroactive to January 1, 2002.

The loss on the sale of CitiPower increased $37 million pre-tax ($24 million after-tax) to $229 million pre-tax ($149 million after-tax; $122 million plus $27 million of cumulative effect) in the second half of 2002 based on actual closing amounts and exchange rates. See the "Discontinued Operations" section of this note for the total revenues and pretax profit (loss) of the discontinued operations of CitiPower.

<u>2001</u>

In March 2001, CSWE, a subsidiary company, completed the sale of Frontera, a generating plant that the FERC required to be divested in connection with the merger of AEP and CSW. The sale proceeds were $265 million and resulted in an after-tax gain of $46 million ($73 million pre-tax).

In July 2001, through a wholly-owned subsidiary, we sold our 50% interest in a 120-megawatt generating plant located in Mexico. The sale resulted in an after tax gain of approximately $11 million.

In July 2001, we sold coal mines in Ohio and West Virginia and agreed to purchase approximately 34 million tons of coal from the purchaser of the mines through 2008. The sale had a nominal impact on our results of operations and cash flows.

In December 2001, we completed the sale of our ownership interests in the Virginia and West Virginia PCS (Personal Communications Services) Alliances for stock, resulting in an after tax gain of approximately $7 million. Subsequently during 2002, due to decreasing market value of the shares received from the sale, we reduced the value of them to zero.

DISCONTINUED OPERATIONS

Management periodically assesses the overall AEP business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify the operations of those businesses or operations as discontinued operations. The assets and liabilities of these discontinued operations are classified as Assets and Liabilities Held for Sale until the time that they are sold. At the time they are sold they are reclassified to Assets and Liabilities of Discontinued Operations on the Consolidated Balance Sheets for all periods presented. Assets and liabilities that are held for sale, but do not qualify as a discontinued operations are reflected as Assets and Liabilities Held for Sale both while they are held for sale and after they have been sold, for all periods presented.

Certain of our operations were determined to be discontinued operations and have been classified as such in 2003, 2002 and 2001. Results of operations of these businesses have been reclassified as shown in the following table:

	SEE-BOARD	CitiPower	Eastex	Pushan Power Plant	LIG	U.K. Generation Plants	Total
2003 Revenue	$-	$-	$58	$60	$653	$125	$896
2003 Pretax Profit (Loss)	-	(20)	(23)	4	(122)	(713)	(874)
2003 Earnings (Loss) After Tax	16	(13)	(14)	4	(91)	(507)	(605)
2002 Revenue	694	204	73	57	507	251	1,786
2002 Pretax Profit (Loss)	180	(190)	(239)	(13)	14	(579)	(827)
2002 Earnings (Loss) After Tax	96	(123)	(156)	(7)	8	(472)	(654)
2001 Revenue	1,451	350	-	57	525	26	2,409
2001 Pretax Profit (Loss)	104	(4)	1	8	(6)	(48)	55
2001 Earnings (Loss) After Tax	88	(6)	-	4	(4)	(41)	41

Assets and liabilities of discontinued operations have been reclassified as follows:

	Eastex (in millions)
As of December 31, 2002	
Current Assets	$15
Total Assets of Discontinued Operations	$15
Current Liabilities	$8
Deferred Credits and Other	4
Total Liabilities of Discontinued Operations	$12

Pushan Power Plant (Investments – Other segment)

In the fourth quarter of 2002, we began active negotiations to sell our interest in the Pushan Power Plant (Pushan) in Nanyang, China to our minority interest partner and a purchase and sale agreement was signed in the fourth quarter of 2003. We expect to close on this transaction by mid 2004. An estimated pre-tax loss on disposal of $20 million pre-tax ($13 million after-tax) was recorded in December 2002, based on an indicative price expression. The estimated pre-tax loss on disposal is classified in Discontinued Operations in our Consolidated Statements of Operations.

Results of operations of Pushan have been reclassified as Discontinued Operations. The assets and liabilities of Pushan have been classified on our Consolidated Balance Sheets as held for sale. We have classified the assets and liabilities as held for sale for longer than 12 months, which is longer than originally expected, due to several unusual circumstances including the SARS outbreak and governmental delays.

Louisiana Intrastate Gas (LIG) (Investments – Gas Operations segment)

After announcing during 2003 that we would be divesting our non-core assets we began actively marketing LIG with the help of an investment advisor. After receiving and analyzing initial bids during the fourth quarter 2003 we recorded a $133.9 million pre-tax ($99 million after-tax) impairment loss; of this loss, $128.9 million pre-tax relates to the impairment of goodwill and $5 million pre-tax relates to other charges. In February 2004, we signed a definitive agreement to sell the pipeline portion of LIG. We anticipate the sale will be completed during the second quarter of 2004 and that the impact on results of operations in 2004 will not be significant. The assets and liabilities of LIG are classified as held for sale on our Consolidated Balance Sheets and the results of operations (including the above-mentioned impairments and other related charges) are classified in Discontinued Operations in our Consolidated Statements of Operations.

U.K. Generation Plants (Investments – UK Operations segment)

In December 2001, we acquired two coal-fired generation plants (U.K. Generation) in the U.K. for a cash payment of $942.3 million and assumption of certain liabilities. Subsequently and continuing through 2002, wholesale U.K. electric power prices declined sharply as a result of domestic over-capacity and static demand. External industry forecasts and our own projections made during the fourth quarter of 2002 indicated that this situation may extend many years into the future. As a result, the U.K. Generation fixed asset carrying value at year-end 2002 was substantially impaired. A December 2002 probability-weighted discounted cash flow analysis of the fair value of our U.K. Generation indicated a 2002 pre-tax impairment loss of $548.7 million ($414 million after-tax). This impairment loss is included in 2002 Discontinued Operations on our Consolidated Statements of Operations.

Management has retained an investment advisor to assist in determining the best methodology to exit the U.K. business. An information memorandum was distributed for the sale of our U.K. Generation and based on current information we recorded a $577 million pre-tax charge ($375 after-tax), including asset impairments of $420.7 million during the fourth quarter of 2003 to write down the value of the assets to their estimated realizable value. Additional charges of $156.7 million pre-tax were also recorded in December 2003 including $122.2 million related to the net loss on certain cash flow hedges previously recorded in Accumulated Other Comprehensive Income that has been reclassified into earnings as a result of management's determination that the hedged event is no longer probable of occurring and $34.5 million related to a first quarter 2004 sale of certain power contracts. The assets and liabilities of U.K. Generation have been classified as held for sale on our Consolidated Balance Sheets and the results of operations are included in Discontinued Operations on our Consolidated Statements of Operations. We anticipate the sale of the U.K. Generation plants during 2004.

ASSET IMPAIRMENTS, INVESTMENT VALUE LOSSES AND OTHER RELATED CHARGES

In 2003, AEP recorded pre-tax impairments of assets (including goodwill) and investments totaling $1.4 billion [consisting of approximately $650 million related to Asset Impairments ($610 million) and Other Related Charges ($40 million), $70 million related to Investment Value Losses, $711 million related to Discontinued Operations ($550 million of impairments and $161 million of other charges) and $6 million related to charges recorded for Excess Real Estate in Maintenance and Other Operation in the Consolidated Statements of Operations] that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit non-core businesses and other factors.

In 2002, AEP recorded pre-tax impairments of assets (including goodwill) and investments totaling $1.7 billion (consisting of approximately $318 million related to Asset Impairments, $321 million related to Investment Value Losses, $938 million related to Discontinued Operations and $88 million related to charges recorded in other lines within the Consolidated Statements of Operations) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, and other factors. These impairments exclude the transitional goodwill impairment loss from adoption of SFAS 142 (see Notes 2 and 3).

The categories of impairments include:

	2003	2002 (in millions)	2001
Asset Impairments and Other Related Charges (Pre-tax)			
AEP Coal	$67	$60	$-
HPL and Other	315	-	-
Power Generation Facility	258	-	-
Blackhawk Coal Company	10	-	-
Ft. Davis Wind Farm	-	5	-
Texas Plants	-	38	-
Newgulf Facility	-	12	-
Excess Equipment	-	24	-
Nordic Trading	-	5	-
Excess Real Estate	-	16	-
Telecommunications – AEPC/C3	-	158	-
Total	$650	$318	$-
Investment Value Losses (Pre-tax)			
Independent Power Producers	$70	$-	$-
Water Heater Assets	-	3	-
South Coast Power Investment	-	63	-
Telecommunications – AFN	-	14	-
AEP Gas Power Systems	-	12	-
Grupo Rede Investment – Vale	-	217	-
Technology Investments	-	12	-
Total	$70	$321	$-
"Impairments and Other Related Charges" and "Operations" Included in Discontinued Operations (After-tax)			
Impairments and Other Related Charges:			
U.K. Generation Plants	$(375)	$(414)	$-
Louisiana Intrastate Gas	(99)	-	-
CitiPower	-	(122)	-
Eastex	-	(142)	-
SEEBOARD	-	24	-
Pushan	-	(13)	-
Total*	(474)	(667)	-
Operations:			
U.K. Generation Plants	(132)	(58)	(41)
Louisiana Intrastate Gas	8	8	(4)
CitiPower	(13)	(1)	(6)
Eastex	(14)	(14)	-
SEEBOARD	16	72	88
Pushan	4	6	4
Total	(131)	13	41
Total Discontinued Operations	$(605)	$(654)	$41

* See the "Dispositions" and "Discontinued Operations" sections of this note for the pre-tax impairment figures.

ASSETS HELD FOR SALE

Telecommunications (Investments – Other segment)

We developed businesses to provide telecommunication services to businesses and other telecommunication companies through broadband fiber optic networks. The businesses included AEP Communications, LLC (AEPC), C3 Communications, Inc. (C3), and a 50% share of AFN, LLC (AFN), a joint venture. Due to the difficult economic conditions in these businesses and the overall telecommunications industry, the AEP Board approved in December 2002 a plan to cease operations of these businesses. We took steps to market the assets of the businesses to potential interested buyers in the fourth quarter of 2002.

We completed the sale of substantially all the assets of C3 in the first quarter of 2003 as discussed in the "Dispositions" section of this note. AFN closed on the sale of substantially all of its assets in January 2004 with no significant additional effect on results of operations in 2004. The sale of remaining telecommunication assets is proceeding.

An estimated pre-tax impairment loss of $158.5 million ($76.3 million related to AEPC and $82.2 million related to C3) was recorded in December 2002 and is classified in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations. An estimated pre-tax loss in value of the investment in AFN of $13.8 million was recorded in December 2002 and is classified in Investment Value Losses in our Consolidated Statements of Operations. The estimated losses were based on indicative bids by potential buyers. Property, Plant and Equipment, net of accumulated depreciation, of the telecommunication businesses have been classified on our Consolidated Balance Sheets as held for sale in 2002.

AEP Coal (Investments – Other segment)

In October 2001, we acquired out of bankruptcy certain assets and assumed certain liabilities of nineteen coal mine companies formerly known as "Quaker Coal" and renamed "AEP Coal." During 2002 the coal operations suffered from a decline in prices and adverse mining factors resulting in significantly reduced mine productivity and revenue. Based on an extensive review of economically accessible reserves and other factors, future mine productivity and production is expected to continue below historical levels. In December 2002, a probability-weighted discounted cash flow analysis of fair value of the mines was performed which indicated a 2002 pre-tax impairment loss of $59.9 million including a goodwill impairment of $3.6 million as discussed in Note 3. This impairment loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

In 2003, as a result of management's decision to exit our non-core businesses, we retained an advisor to facilitate the sale of AEP Coal. In the fourth quarter of 2003, after considering the current bids and all other options, we recorded a $66.6 million pre-tax ($43.6 million after-tax) charge comprised of a $29.4 million asset impairment, a $25.2 million charge related to accelerated remediation cost accruals and $12 million charge (accrued at December 31, 2003) related to a royalty agreement. These impairment losses were included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The assets and liabilities of AEP Coal that are held for sale have been included in Assets and Liabilities Held for Sale in our Consolidated Balance Sheets at December 31, 2003 and 2002.

Texas Plants (Utility Operations segment)

In September 2002, AEP indicated to ERCOT its intent to deactivate 16 gas-fired power plants (8 TCC plants and 8 TNC plants). ERCOT subsequently conducted reliability studies, which determined that seven plants (4 TCC plants and 3 TNC plants) would be required to ensure reliability of the electricity grid. As a result of those studies, ERCOT and AEP mutually agreed to enter into reliability must run (RMR) agreements, which expired in December 2002, and were subsequently renewed through December 2003. However, certain contractual provisions provided ERCOT with a 90-day termination clause, if the contracted facility was no longer needed to ensure reliability of the electricity grid. With ERCOT's approval, AEP proceeded with its planned deactivation of the remaining nine plants. In August 2003, pursuant to contractual terms, ERCOT provided notification to AEP of its intent to cancel a RMR agreement at one of the TNC plants. Upon termination of the agreement, AEP proceeded with its planned deactivation of the plant. In December 2003, AEP and ERCOT mutually agreed to new RMR contracts at six plants (4 TCC plants and 2 TNC plants) through December 2004, subject to ERCOT's 90 day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate TNC plants, a write-down of utility assets of approximately $34.2 million (pre-tax) was recorded in Asset Impairments and Other Related Charges expense during the third quarter 2002 on our Consolidated Statements of Operations. The decision to deactivate the TCC plants resulted in a write-down of utility assets of approximately $95.6 million (pre-tax), which was deferred and recorded in Regulatory Assets during the third quarter 2002 in our Consolidated Balance Sheets.

During the fourth quarter of 2002, evaluations continued as to whether assets remaining at the deactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional asset impairment charge to Asset Impairments and Other Related Charges expense of $3.9 million (pre-tax) in the fourth quarter of 2002. In addition, TNC recorded related fuel inventory and materials and supplies write-downs of $2.6 million ($1.2 million in Fuel for Electric Generation and $1.4 million in Maintenance and Other Operation). Similarly, TCC recorded an additional asset impairment write-down of $6.7 million (pre-tax), which was deferred and recorded in Regulatory Assets in the fourth quarter of 2002. TCC also recorded related inventory write-downs of $14.9 million which was deferred and recorded in Regulatory Assets in the fourth quarter 2002.

The total Texas plant asset impairment of $38.1 million pre-tax in 2002 (all related to TNC) is included in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as RMR status. During the fourth quarter of 2003, after receiving bids from interested buyers, we recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to Assets Held for Sale. In accordance with Texas legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the 2004 Texas true-up proceeding. See Texas Restructuring section of Note 6, "Customer Choice and Industry Restructuring," for further discussion of the divestiture plan, anticipated timeline and true-up proceeding.

The assets and liabilities of the entities held for sale at December 31, 2003 and 2002 are as follows:

December 31, 2003	Pushan Power Plant	U.K. Generation Plants	AEP Coal	Texas Plants	LIG	Total
			(in millions)			
Assets:						
Current Assets	$24	$1,245	$6	$57	$50	$1,382
Property, Plant and Equipment, Net	142	99	13	797	171	1,222
Regulatory Assets	-	-	-	49	-	49
Spent Nuclear Fuel and Decommissioning Trusts	-	-	-	125	-	125
Goodwill	-	-	-	-	15	15
Long-term Risk Management Assets	-	274	-	-	-	274
Other	-	6	-	-	9	15
Total Assets Held for Sale	$166	$1,624	$19	$1,028	$245	$3,082
Liabilities:						
Current Liabilities	$26	$988	$-	$-	$61	$1,075
Long-term Debt	20	-	-	-	-	20
Long-term Risk Management Liabilities	-	435	-	-	-	435
Regulatory Liabilities and Deferred Investment Tax Credits	-	-	-	9	-	9
Asset Retirement Obligations and Nuclear Decommissioning Trusts	-	29	-	219	-	248
Employee Benefits and Pension Obligations	-	12	-	-	-	12
Deferred Credits and Other	57	-	14	-	6	77
Total Liabilities Held for Sale	$103	$1,464	$14	$228	$67	$1,876

December 31, 2002	Pushan Power Plant	U.K. Generation Plants	AEP Coal	Texas Plants	LIG	Tele-Communications	Nordic Trading	Newgulf Facility	Excess Equipment	Water Heater Program	Total
					(in millions)						
Assets:											
Current Assets	$19	$571	$4	$70	$62	$-	$35	$-	$-	$1	$762
Property, Plant and Equipment, Net	132	445	38	1,647	169	6	-	6	-	38	2,481
Spent Nuclear Fuel and Decommissioning Trusts	-	-	-	98	-	-	-	-	-	-	98
Goodwill	-	11	-	-	144	-	-	-	-	-	155
Long-term Risk Management Assets	-	61	-	-	-	-	5	-	-	-	66
Other	-	22	-	-	-	-	5	-	12	-	39
Total Assets Held for Sale	$151	$1,110	$42	$1,815	$375	$6	$45	$6	$12	$39	$3,601
Liabilities:											
Current Liabilities	$28	$992	$-	$-	$53	$-	$48	$-	$-	$-	$1,121
Long-term Debt	25	-	-	-	-	-	-	-	-	-	25
Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Long-term Risk Management Liabilities	-	39	-	-	7	-	3	-	-	-	49
Deferred Credits and Other	26	24	15	9	10	-	-	-	-	-	84
Total Liabilities Held for Sale	$79	$1,055	$15	$9	$70	$-	$51	$-	$-	$-	$1,279

ASSETS HELD AND USED

In 2003 and 2002, we recorded the following impairments related to assets (including Goodwill) held and used to Asset Impairments and Other Related Charges on our Consolidated Statements of Operations as discussed below:

Excess Real Estate (Investments – Other segment)

In the fourth quarter of 2002, we began to market an under-utilized office building in Dallas, TX obtained through our merger with CSW. Sale of the facility was projected by the second quarter 2003 and an estimated pre-tax loss on disposal of $15.7 million was recorded in 2002, based on the option sale price. The estimated loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The Property asset of $18 million in 2002 and $36 million in 2001 was previously classified on our Consolidated Balance Sheets as held for sale.

The sale of this office building was not completed by the end of 2003 and as a result the building no longer qualifies for held for sale status. In accordance with SFAS 144 the building will be moved to held and used status for all periods presented as of December 31, 2003. In December 2003 we recorded an additional pre-tax impairment of $6 million based on bids received to date. The impairment is recorded in Maintenance and Other Operation on our Consolidated Statements of Operations. The building will continue to be actively marketed.

HPL and Other (Investments – Gas Operations segment)

HPL owns, or leases, and operates natural gas gathering, transportation and storage operations in Texas. In 2003, management announced that we were in the process of divesting our non-core assets, which includes the assets within our Investments-Gas Operations segment. During the fourth quarter of 2003, based on a probability-weighted after-tax cash flow analysis of the fair value of HPL, we recorded an impairment of $300 million pre-tax ($218 million after-tax), with $150 million pre-tax related to goodwill, reflecting management's decision not to operate HPL as a major trading hub and market indicators supported by the LIG bid process. The cash flow analysis used management's estimate of the alternative likely outcomes of the uncertainties surrounding the continued use of the Bammel facility and other matters (see Note 7) and an after-tax risk free discount rate of 3.3% over the remaining life of the assets.

We also recorded a $15 million pre-tax charge ($10 million after-tax) in the fourth quarter 2003 included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. This charge related to the effect of the write-off of certain HPL and LIG assets and the impairment of goodwill related to our former optimization strategy of LIG assets by AEP Energy Services.

Blackhawk Coal Company (Utility Operations segment)

Blackhawk Coal Company (Blackhawk) is a wholly-owned subsidiary of I&M and was formerly engaged in coal mining operations until they ceased due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the carrying value of the investment was impaired based on an updated valuation reflecting management's decision not to pursue development of potential gas reserves. As a result, a $10.4 million pre-tax charge was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

Power Generation Facility (Investments – Other segment)

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. Juniper will own the Facility and lease it to AEP after construction is completed and we will sublease the Facility to The Dow Chemical Company (Dow).

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation. In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded $496 million of construction work in progress (CWIP) and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since the debt obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the above table of future minimum lease payments.

The current litigation between TEM and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power freed up by TEM contract termination, triggered us to review the project for possible impairment of its reported values. We determined that the value of the Facility was impaired and recorded a $258 million pre-tax impairment ($168 million after-tax) in December 2003 on the CWIP.

See further discussion in Notes 7 and 16.

INVESTMENT VALUE AND OTHER LOSSES

In 2003 and 2002, we recorded the following declines in fair value on investments:

Independent Power Producers (Investments – Other segment)

During the third quarter of 2003, we initiated an effort to sell four domestic Independent Power Producer (IPP) investments accounted for under the equity method. Based on indicative bids, it was determined that an other than temporary impairment existed on two of the equity investments. The impairment was the result of the measurement of fair value that was triggered by our recent decision to sell the assets. A $70.0 million pre-tax ($45.5 million net of tax) loss was recorded in September 2003 as a result of an other than temporary impairment of the equity interest. This loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations. We have received bids on the IPP investments and anticipate a final sale during the first half of 2004.

South Coast Power Investment (Investments – Other segment)

South Coast Power is a 50% owned joint venture that was formed in 1996 to build and operate a merchant closed-cycle gas turbine generator at Shoreham, U.K. South Coast Power is subject to the same adverse wholesale electric power rates described for U.K. Generation Plants above in "Discontinued Operations." A December 2002 projected cash flow estimate of the fair value of the investment indicated a 2002 pre-tax other than temporary impairment of the equity interest (which included the fair value of supply contracts held by South Coast Power and accounted for in accordance with SFAS 133) in the amount of $63.2 million. This loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations in 2002.

Technology Investments (Investments – Other segment)

We previously made investments totaling $11.7 million in four early-stage or startup technologies involving pollution control and procurement. An analysis in December 2002 of the viability of the underlying technologies and the projected performance of the investee companies indicated that the investments were unlikely to be recovered, and an other than temporary impairment of the entire amount of the equity interest under APB 18 was recorded. The loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations.

11. BENEFIT PLANS

In the U.S. we sponsor two qualified pension plans and two nonqualified pension plans. A substantial majority of our employees in the U.S. are covered by either one qualified plan or both a qualified and a nonqualified pension plan. Other postretirement benefit plans are sponsored by us to provide medical and death benefits for retired employees in the U.S.

We also have a foreign pension plan for employees of AEP Energy Services U.K. Generation Limited (Genco) in the U.K. The Genco pension plan had $7 million of accumulated benefit obligations in excess of plan assets at December 31, 2002. The plan was in an overfunded position at December 31, 2003.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2003, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	2003	2002	2003	2002
Change in Benefit Obligation:	(in millions)			
Obligation at January 1	$3,583	$3,292	$1,877	$1,645
Service Cost	80	72	42	34
Interest Cost	233	241	130	114
Participant Contributions	-	-	14	13
Plan Amendments	-	(2)	-	-
Actuarial (Gain) Loss	91	258	192	152
Benefit Payments	(299)	(278)	(92)	(81)
Obligation at December 31	$3,688	$3,583	$2,163	$1,877
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$2,795	$3,438	$723	$711
Actual Return on Plan Assets	619	(371)	122	(57)
Company Contributions (a)	65	6	183	137
Participant Contributions	-	-	14	13
Benefit Payments (a)	(299)	(278)	(92)	(81)
Fair Value of Plan Assets at December, 31	$3,180	$2,795	$950	$723

Funded Status:				
Funded Status at December 31	$(508)	$(788)	$(1,213)	$(1,154)
Unrecognized Net Transition (Asset) Obligation	2	(7)	206	233
Unrecognized Prior Service Cost	(12)	(13)	6	6
Unrecognized Actuarial (Gain) Loss	797	1,020	977	896
Net Asset (Liability) Recognized	$279	$212	$(24)	$(19)

(a) Our contributions and benefit payments include only those amounts contributed directly to or paid directly from plan assets.

Accumulated Benefit Obligation:	2003	2002
	(in millions)	
U.S. Qualified Pension Plans	$3,549	$3,456
U.S. Nonqualified Pension Plans	76	71

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	2003	2002	2003	2002
	(in millions)			
Prepaid Benefit Costs	$325	$255	$-	$-
Accrued Benefit Liability	(46)	(44)	(24)	(19)
Additional Minimum Liability	(723)	(944)	N/A	N/A
Unrecognized Prior Service Costs	39	45	N/A	N/A
Accumulated Other Comprehensive Income	684	900	N/A	N/A
Net Asset (Liability) Recognized	$279	$212	$(24)	$(19)
Increase (Decrease) in Minimum Liability Included in Other Comprehensive Income (Pre-tax)	$(216)	$894	N/A	N/A

N/A = Not Applicable

The asset allocations for our U.S. pension plans at the end of 2003 and 2002, and the target allocation for 2004, by asset category, are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at Yearend 2003	2002
		(in percentage)	
Equity	70	71	67
Fixed Income	28	27	32
Cash and Cash Equivalents	2	2	1
Total	100	100	100

The asset allocations for our U.S. other postretirement benefit plans at the end of 2003 and 2002, and target allocation for 2004, by asset category, are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at Yearend 2003	2002
		(in percentage)	
Equity	70	61	41
Fixed Income	28	36	38
Cash and Cash Equivalents	2	3	21
Total	100	100	100

Our investment strategy for our employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk.

The value of our qualified plans' assets increased from $2.795 billion at December 31, 2002 to $3.180 billion at December 31, 2003. The qualified plans paid $292 million in benefits to plan participants during 2003 (nonqualified plans paid $7 million in benefits). The status of our plans remains in an underfunded position (plan assets are less than projected benefit obligations) of $508 million at December 31, 2003. Due to the pension plans currently being underfunded, we recorded income in Other Comprehensive Income (OCI) of $154 million, and a reduction in the Deferred Income Tax Asset of $76 million, offset by a reduction to Minimum Pension Liability of $234 million and a reduction in adjustments for unrecognized costs of $4 million. The charge to OCI does not affect earnings or cash flow. Also, due to the current underfunded status of our qualified plans, we expect to make cash contributions to our U.S. pension plans of approximately $41 million in 2004.

At December 31, 2003 and 2002, the projected benefit obligation, accumulated benefit obligation, and fair value of U.S. plan assets of the U.S. pension plans with an accumulated benefit obligation in excess of plan assets, were as follows:

	U.S. Plans	
End of Year	2003	2002
	(in millions)	
Projected Benefit Obligation	$3,688	$3,583
Accumulated Benefit Obligation	3,625	3,527
Fair Value of Plan Assets	3,180	2,795
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	445	732

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

The weighted-average assumptions as of December 31, used in the measurement of our benefit obligations are shown in the following tables:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2003	2002	2003	2002
	(in percentages)			
Discount Rate	6.25	6.75	6.25	6.75
Rate of Compensation Increase	3.7	3.7	N/A	N/A

In determining the discount rate in the calculation of future pension obligations we review the interest rates of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. As a result of a decrease in this benchmark rate during 2003, we determined that a decrease in our discount rate from 6.75% at December 31, 2002 to 6.25% at December 31, 2003 was appropriate.

The rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 8.5% per year, with an average increase of 3.7%.

Information about the expected cash flows for the U.S. pension (qualified and non-qualified) and other postretirement benefit plans is as follows:

	U.S. Pension Plans	U.S. Other Postretirement Benefit Plans
	(in millions)	
Employer Contributions		
2003	$65	$183
2004 (expected)	41	180

The table below reflects the total benefits expected to be paid from the plan or from our assets, including both our share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and other postretirement benefits are as follows:

	U.S. Pension Benefits	U.S. Other Postretirement Benefit Plans
	(in millions)	
2004	$293	$106
2005	300	114
2006	310	123
2007	325	132
2008	335	140
Years 2009 to 2013, in Total	1,840	836

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater. The contribution to the other postretirement benefit plans' trusts is generally based on the amount of the other postretirement benefit plans' expense for accounting purposes and is provided for in agreements with state regulatory authorities.

The following table provides the components of our net periodic benefit cost (credit) for the plans for fiscal years 2003, 2002 and 2001:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(in millions)					
Service Cost	$80	$72	$69	$42	$34	$30
Interest Cost	233	241	232	130	114	114
Expected Return on Plan Assets	(318)	(337)	(338)	(64)	(62)	(61)
Amortization of Transition (Asset) Obligation	(8)	(9)	(8)	28	29	30
Amortization of Prior-service Cost	(1)	(1)	-	-	-	-
Amortization of Net Actuarial (Gain) Loss	11	(10)	(24)	52	27	18
Net Periodic Benefit Cost (Credit)	(3)	(44)	(69)	188	142	131
Curtailment Loss	-	-	-	-	-	1
Net Periodic Benefit Cost (Credit) After Curtailments	$(3)	$(44)	$(69)	$188	$142	$132

The weighted-average assumptions as of January 1, used in the measurement of our benefit costs are shown in the following tables:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(in percentage)					
Discount Rate	6.75	7.25	7.50	6.75	7.25	7.50
Expected Return on Plan Assets	9.00	9.00	9.00	8.75	8.75	8.75
Rate of Compensation Increase	3.7	3.7	3.2	N/A	N/A	N/A

The expected return on plan assets for 2003 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as Unrelated Business Income Taxes) was reduced to 8.35%.

The assumptions used for other postretirement benefit plan measurement purposes are shown below:

Health Care Trend Rates:	2003	2002
	(in percentage)	
Initial	10.0	10.0
Ultimate	5.0	5.0
Year Ultimate Reached	2008	2008

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$26	$(21)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	315	(257)

We have not yet determined the impact of the Medicare Prescription Drug Improvement and Modernization Act of 2003 on our other postretirement benefit plans' accumulated benefit obligation and periodic benefit cost. See FASB Staff Position No. 106-1 in Note 2 for additional information on the potential impact on our results of operations, cash flows and financial condition.

AEP Savings Plans

We sponsor various defined contribution retirement savings plans eligible to substantially all non-United Mine Workers of America (UMWA) U.S. employees. These plans include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. On January 1, 2003, the two major AEP Savings Plans merged into a single plan. Beginning in 2001, and continuing under the single merged plan, our contributions to the plans increased from 50% to 75% of the first 6% of eligible employee compensation. The cost for contributions to these plans totaled $57.0 million in 2003, $60.1 million in 2002 and $55.6 million in 2001.

Other UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds.

The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2003, 2002 and 2001.

12. STOCK-BASED COMPENSATION

The American Electric Power System 2000 Long-Term Incentive Plan (the Plan) authorizes the use of 15,700,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. The Plan was adopted in 2000 by the Board of Directors and shareholders.

Stock-based compensation awards granted by AEP include restricted stock units, restricted shares, performance share units and stock options. Restricted stock units vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st for three years following the grant date. Amounts equivalent to cash dividends on the units accrue as additional units. AEP awarded 105,910 restricted stock units, including dividends, in 2003, with a weighted-average grant-date fair value of $22.17 per unit. Compensation cost is recorded over the vesting period, based on the market value on the grant date. Expense associated with units that are forfeited is reversed in the period of forfeiture.

AEP awarded 300,000 restricted shares in January 2004, which vest over periods ranging from 1 to 8 years. Compensation cost will be recorded over the vesting period based on the market value of $30.76 per unit on the grant date.

Performance share units are equal in value to shares of AEP common stock but are subject to an attached performance factor ranging from 0% to 200%. The performance factor is determined at the end of the performance period based on performance measure(s) established for each grant at the beginning of the performance period by the Human Resources Committee of the Board of Directors. Performance share units are typically paid in cash at the end of a three-year vesting period, unless they are needed to satisfy a participant's stock ownership requirement, in which case they are mandatorily deferred as phantom stock units until the end of the participants AEP career. Phantom stock units have a value equivalent to AEP common stock and are typically paid in cash upon the participant's termination of employment. The compensation cost for performance share units is recorded over the vesting period and both the performance share and phantom stock unit liability is adjusted for changes in fair market value. Amounts equivalent to cash dividends on both performance share and phantom stock units accrue as additional units.

Under the Plan, the exercise price of all stock option grants must equal or exceed the market price of AEP's common stock on the date of grant, and in accordance with its policy, AEP does not record compensation expense. AEP generally grants options that have a ten-year life and vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1 following the first, second and third anniversary of the grant date.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. Outstanding CSW stock options will continue in effect until all options are exercised, cancelled or expired. Under the CSW stock option plan, the option price was equal to the fair market value of the stock on the grant date. All CSW options fully vested upon the completion of the merger and expire 10 years after their original grant date.

A summary of AEP stock option transactions in fiscal periods 2003, 2002 and 2001 is as follows:

	2003		2002		2001	
	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	8,787	$34	6,822	$37	6,610	$36
Granted	927	$28	2,923	$27	645	$45
Exercised	(23)	$27	(600)	$36	(216)	$38
Forfeited	(597)	$33	(358)	$41	(217)	$37
Outstanding at end of year	9,094	$33	8,787	$34	6,822	$37
Options exercisable at end of year	3,909	$36	2,481	$36	395	$43
Weighted average exercise price of options:						
-Granted above Market Price		N/A		$27		N/A
-Granted at Market Price		$28		$27		$45

The following table summarizes information about AEP stock options outstanding at December 31, 2003:

Options Outstanding

Range of Exercise Prices	Number Outstanding (in thousands)	Weighted Average Remaining Life (in years)	Weighted Average Exercise Price
$25.73 - $27.95	3,530	9.1	$27.28
$34.58 - $41.50	5,054	6.6	$35.74
$43.79 - $49.00	510	7.5	$45.98
	9,094	7.6	$33.03

Options Exercisable

Range of Exercise Prices	Number Outstanding (in thousands)	Weighted Average Exercise Price
$25.73 - $27.95	52	$27.06
$34.58 - $41.50	3,610	$35.78
$43.79 - $49.00	247	$46.57
	3,909	$36.35

The proceeds received from exercised stock options are included in common stock and paid-in capital.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions used to estimate the fair value of AEP options granted:

	2003	2002	2001
Risk Free Interest Rate	3.92%	3.53%	4.87%
Expected Life	7 years	7 years	7 years
Expected Volatility	27.57%	29.78%	28.40%
Expected Dividend Yield	4.86%	6.15%	6.05%
Weighted average fair value of options:			
-Granted above Market Price	N/A	$4.58	N/A
-Granted at Market Price	$5.26	$4.37	$8.01

13. BUSINESS SEGMENTS

Our segments and their related business activities are as follows:

Utility Operations
- Domestic generation of electricity for sale to retail and wholesale customers
- Domestic electricity transmission and distribution

*Investments - Gas Operations**
- Gas pipeline and storage services

*Investments - UK Operations***
- International generation of electricity for sale to wholesale customers
- Coal procurement and transportation to AEP plants and third parties

Investments – Other
- Coal mining, bulk commodity barging operations and other energy supply businesses

* Operations of Louisiana Intrastate Gas were classified as discontinued during 2003.
** UK Operations were classified as discontinued during 2003.

The tables below present segment information for the twelve months ended December 31, 2003, 2002 and 2001. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other*	Reconciling Adjustments	Consolidated
2003				(in millions)			
Revenues from:							
External Customers	$10,871	$3,097	$-	$ 577	$-	$ -	$14,545
Other Operating Segments	-	192	-	96	11	(299)	-
Discontinued Operations, Net of Tax	-	(91)	(507)	(7)	-	-	(605)
Cumulative Effect of Accounting Changes, Net of Tax	237	(23)	(21)	-	-	-	193
Net Income (Loss)	1,455	(404)	(528)	(284)	(129)	-	110
Depreciation, Depletion and Amortization Expense	1,241	18	-	39	1	-	1,299
Total Assets	30,816	2,405	1,705	1,697	14,925	(14,804)	36,744
Assets Held for Sale	1,033	240	1,624	185	-	-	3,082
Investments in Equity Method Subsidiaries	-	36	38	87	-	-	161
Gross Property Additions	1,323	25	-	10	-	-	1,358

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

2002	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other*	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$10,446	$2,071	$-	$791	$-	$ -	$13,308
Other Operating Segments	-	222	-	147	10	(379)	-
Discontinued Operations, Net of Tax	-	8	(472)	(190)	-	-	(654)
Cumulative Effect of Accounting Changes, Net of Tax	-	-	-	(350)	-	-	(350)
Net Income (Loss)	1,154	(91)	(472)	(1,062)	(48)	-	(519)
Depreciation, Depletion and Amortization Expense	1,268	13	-	67	-	-	1,348
Total Assets	29,431	3,912	1,215	1,947	18,388	(19,003)	35,890
Assets Held for Sale	1,866	375	1,150	210	-	-	3,601
Investments in Equity Method Subsidiaries	-	35	-	137	-	-	172
Gross Property Additions	1,517	47	-	25	96	-	1,685

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

2001	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other*	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$10,546	$1,797	$-	$410	$-	$-	$12,753
Other Operating Segments	-	-	-	86	5	(91)	-
Discontinued Operations, Net of Tax	-	(4)	(41)	86	-	-	41
Extraordinary Items, Net of Tax	(48)	-	-	-	-	-	(48)
Cumulative Effect, Net of Tax	-	-	-	18	-	-	18
Net Income (Loss)	911	87	(41)	86	(72)	-	971
Depreciation, Depletion and Amortization Expense	1,193	15	-	25	-	-	1,233
Gross Property Additions	1,397	14	-	137	98	-	1,646

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

14. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

In the first quarter of 2001, we adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. We recorded a favorable transition adjustment to Accumulated Other Comprehensive Income (Loss) of $27 million at January 1, 2001 in connection with the adoption of SFAS 133. Derivatives included in the transition adjustment are interest rate swaps, foreign currency swaps and commodity swaps, options and futures. Most of the derivatives identified in the transition adjustment were designated as cash flow hedges and relate to foreign operations.

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position at fair value. Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies, and has been designated, as part of a hedging relationship and further, on the type of hedging relationship. We designate the hedging instrument, based on the exposure being hedged, as a fair value hedge, a cash flow hedge or a hedge of a net investment in a foreign operation. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. These contracts are not reported at fair value, as otherwise required by SFAS 133.

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Revenues in the Consolidated Statement of Operations during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Other Accumulated Comprehensive Income and subsequently reclassify it to Revenues in the Consolidated Statement of Operations when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in Revenues during the period of change. For a hedge of a net investment in a foreign currency, we include the effective portion of the gain or loss in Other Accumulated Comprehensive Income as part of the cumulative translation adjustment. We recognize any ineffective portion of the gain or loss in Revenues immediately during the period of change.

We recognize all derivative instruments at fair value in our Consolidated Balance Sheets as either "Risk Management Assets" or "Risk Management Liabilities." We do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in Revenues in the Consolidated Statement of Operations on a net basis, with the exception of physically settled Resale Gas Contracts for the purchase of natural gas. The unrealized and realized gains and losses on these Resale Gas Contracts are presented as Purchased Gas for Resale in the Consolidated Statement of Operations.

Fair Value Hedging Strategies

We enter into natural gas forward and swap transactions to hedge natural gas inventory. The purpose of the hedging activity is to protect the natural gas inventory against changes in fair value due to changes in the spot gas prices. During the year ended December 31, 2003, we recognized a pre-tax loss of approximately $3.4 million within revenues related to hedge ineffectiveness and changes in time value excluded from the assessment of hedge ineffectiveness.

We enter into interest rate forward and swap transactions for interest rate risk exposure management purposes. The interest rate forward and swap transactions effectively modifies our exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. We do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

We enter into forward contracts to protect against the reduction in value of forecasted cash flows resulting from transactions denominated in foreign currencies. When the dollar strengthens significantly against the foreign currencies, the decline in value of future foreign currency revenue is offset by gains in the value of the forward contracts designated as cash flow hedges. Conversely, when the dollar weakens, the increase in the value of future foreign currency cash flows is offset by losses in the value of forward contracts. We do not hedge all foreign currency exposure.

We enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. These transactions effectively modify our exposure to interest risk by converting a portion of our floating-rate debt to a fixed rate. We do not hedge all interest rate exposure.

We enter into forward and swap transactions for the purchase and sale of electricity and natural gas to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into contracts to protect margins for a portion of future sales and generation revenues. We do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets at December 31, 2003 are:

	Hedging Assets	Hedging Liabilities	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to Be Reclassified to Earnings during the Next 12 Months
			(in millions)	
Power and Gas	$21	$(121)	$(65)	$(58)
Interest Rate	-	(7)	(9)*	(8)
Foreign Currency	-	(30)	(20)	(20)
			$(94)	$(86)

* Includes $6 million loss recorded in an equity investment.

The net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2003 are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is five years.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2003:

	(in millions)
Beginning Balance, January 1, 2003	$(16)
Changes in fair value	(79)
Reclasses from AOCI to net gain	1
Ending Balance, December 31, 2003	$(94)

Hedge of Net Investment in Foreign Operations

In 2001 and 2002, we used foreign denominated fixed-rate debt to protect the value of our investments in foreign subsidiaries in the U.K. Realized gains and losses from these hedges are not included in the income statement, but are shown in the cumulative translation adjustment account included in Other Accumulated Comprehensive Income.

During 2002, we recognized $64 million of net losses, included in the cumulative translation adjustment, related to the foreign denominated fixed-rate debt.

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of significant financial instruments at December 31, 2003 and 2002 are summarized in the following tables.

	2003		2002	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)		(in millions)	
Long-term Debt	$14,101	$14,621	$10,190	$10,535
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption*	76	76	84	77
Trust Preferred Securities	-	-	321	324

* See Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries for the effect of SFAS 150 in 2003.

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments which are classified as available for sale for decommissioning and SNF disposal, reported in "Spent Nuclear Fuel and Decommissioning Trusts" and "Assets Held for Sale" on our Consolidated Balance Sheets, are recorded at market value in accordance with SFAS 115 "Accounting for Certain Investments in Debt and Equity Securities." At December 31, 2003 and 2002, the fair values of the trust investments were $1,107 million and $969 million, respectively, and had a cost basis of $995 million and $909 million, respectively. The change in market value in 2003, 2002, and 2001 was a net unrealized holding gain of $53 million and a net unrealized holding loss of $33 million and $11 million, respectively.

15. INCOME TAXES

The details of our consolidated income taxes before discontinued operations, extraordinary items, and cumulative effect as reported are as follows:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Federal:			
Current	$297	$307	$411
Deferred	34	(60)	54
Total	331	247	465
State and Local:			
Current	19	32	61
Deferred	1	28	34
Total	20	60	95
International:			
Current	7	8	(7)
Deferred	-	-	-
Total	7	8	(7)
Total Income Tax as Reported Before Discontinued Operations, Extraordinary Items and Cumulative Effect	$358	$315	$553

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

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Net Income (Loss)	$110	$(519)	$971
Discontinued Operations (net of income tax of $312 million, $174 million and $14 million in 2003, 2002 and 2001, respectively)	605	654	(41)
Extraordinary Items (net of income tax of $20 million in 2001)	-	-	48
Cumulative Effect of Accounting Change (net of income tax of $138 million in 2003)	(193)	350	(18)
Preferred Stock Dividends	9	11	10
Income Before Preferred Stock Dividends of Subsidiaries	531	496	970
Income Taxes Before Discontinued Operations, Extraordinary Items and Cumulative Effect	358	315	553
Pre-Tax Income	$889	$811	$1,523
Income Taxes on Pre-Tax Income at Statutory Rate *(35%)*	$311	$284	$533
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	40	32	48
Asset Impairments and Investment Value Losses	23	4	-
Investment Tax Credits (net)	(33)	(35)	(37)
Tax Effects of International Operations	8	27	(22)
Energy Production Credits	(15)	(14)	-
State Income Taxes	13	39	62
Other	11	(22)	(31)
Total Income Taxes as Reported Before Discontinued Operations, Extraordinary Items and Cumulative Effect	$358	$315	$553
Effective Income Tax Rate	40.3%	38.8%	36.3%

The following table shows our elements of the net deferred tax liability and the significant temporary differences.

	As of December 31,	
	2003	2002
	(in millions)	
Deferred Tax Assets	$3,354	$2,604
Deferred Tax Liabilities	(7,311)	(6,520)
Net Deferred Tax Liabilities	$(3,957)	$(3,916)
Property Related Temporary Differences	$(2,836)	$(3,195)
Amounts Due From Customers For Future Federal Income Taxes	(389)	(360)
Deferred State Income Taxes	(416)	(422)
Transition Regulatory Assets	(254)	(234)
Regulatory Assets Designated for Securitization	(281)	(310)
Deferred Income Taxes on Other Comprehensive Loss	306	326
All Other (net)	(87)	279
Net Deferred Tax Liabilities	$(3,957)	$(3,916)

We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. We have received Revenue Agent's Reports from the IRS for the years 1991 through 1996, and have filed protests contesting certain proposed adjustments. Returns for the years 1997 through 2000 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.

We join in the filing of a consolidated federal income tax return with our affiliated companies in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

16. LEASES

Leases of property, plant and equipment are for periods up to 99 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for non-regulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Lease Payments on Operating Leases	$330	$346	$292
Amortization of Capital Leases	64	65	82
Interest on Capital Leases	9	14	22
Total Lease Rental Costs	$403	$425	$396

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

	December 31,	
	2003	2002
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	$37	$40
Distribution	15	15
Other	470	687
Total Property, Plant and Equipment	522	742
Accumulated Amortization	218	299
Net Property, Plant and Equipment Under Capital Leases	$304	$443
Obligations Under Capital Leases:		
Noncurrent Liability	$131	$170
Liability Due Within One Year	51	58
Total Obligations under Capital Leases	$182	$228

Future minimum lease payments consisted of the following at December 31, 2003:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2004	$63	$291
2005	43	255
2006	34	237
2007	31	227
2008	18	214
Later Years	31	2,331
Total Future Minimum Lease Payments	220	$3,555
Less Estimated Interest Element	38	
Estimated Present Value of Future Minimum Lease Payments	$182	

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. The Facility is a "qualifying cogeneration facility" for purposes of PURPA. Construction of the Facility was begun by Katco Funding, Limited Partnership (Katco), an unrelated unconsolidated special purpose entity. Katco assigned its interest in the Facility to Juniper in June 2003.

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

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation (COD). In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded $496 million of construction work in progress (CWIP) and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since the debt obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the above table of future minimum lease payments.

We are the construction agent for Juniper. We expect to achieve COD in the spring of 2004, at which time the obligation to make payments under the lease agreement will begin to accrue and we will sublease the Facility to The Dow Chemical Company (Dow). If COD does not occur on or before March 14, 2004, Juniper has the right to terminate the project. In the event the project is terminated before COD, we have the option to either purchase the Facility for 100% of Juniper's acquisition cost (in general, the outstanding debt and equity associated with the Facility) or terminate the project and make a payment to Juniper for 89.9% of project costs (in general, the acquisition cost less certain financing costs).

The initial term of the lease agreement between Juniper and AEP commences on COD and continues for five years. The lease contains extension options, and if all extension options are exercised, the total term of the lease will be 30 years. AEP's lease payments to Juniper during the initial term and each extended term are sufficient for Juniper to make required debt payments under Juniper's debt financing associated with the Facility and provide a return on equity to the investors in Juniper. We have the right to purchase the Facility for the acquisition cost during the last month of the initial term or on any monthly rent payment date during any extended term. In addition, we may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if we have arranged a sale of the Facility to an unaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow. If the lease were renewed for up to a 30-year lease term, we may further renew the lease at fair market value subject to Juniper's approval, purchase the Facility at its acquisition cost, or sell the Facility, on behalf of Juniper, to an independent third party. If the Facility is sold and the proceeds from the sale are insufficient to pay all of Juniper's acquisition costs, we may be required to make a payment (not to exceed $396 million) to Juniper of the excess of Juniper's acquisition costs over the proceeds from the sale, provided that we would not be required to make any payment if we have made the additional rental prepayment described below. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report the debt related to the Facility on our balance sheet, the fair value of the liability for our guarantee (the $396 million payment discussed above) is not separately reported.

At December 31, 2003, Juniper's acquisition costs for the Facility totaled $496 million, and total costs for the completed Facility are currently expected to be approximately $525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR. Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately $18 million represent future minimum payments for interest on Juniper's financing structure during the initial term calculated using the indexed LIBOR rate (1.15% at December 31, 2003). An additional rental prepayment (up to $396 million) may be due on June 30, 2004 unless Juniper has refinanced its present debt financing on a long-term basis. Juniper is currently planning to refinance by June 30, 2004. The Facility is collateral for the debt obligation of Juniper. At December 31, 2003, we reflected $396 million of the $496 million recorded obligation as long-term debt due within one year. Our maximum required cash payment as a result of our financing transaction with Juniper is $396 million as well as interest payments during the lease term. Due to the treatment of the Facility as a financing of an owned asset, the recorded liability of $496 million is greater than our maximum possible cash payment obligation to Juniper.

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as non-conforming.

See further discussion in Notes 7 and 10.

Gavin Lease

OPCo has entered into an agreement with JMG, an unrelated special purpose entity. JMG has a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from commercial paper, pollution control bonds and other bonds. JMG was formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. JMG owns the Gavin Scrubber and leases it to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease. Payments under the lease agreement are based on JMG's cost of financing (both debt and equity) and include an amortization component plus the cost of administration. OPCo and AEP do not have an ownership interest in JMG and do not guarantee JMG's debt.

At any time during the lease, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber on behalf of JMG. The initial 15-year lease term is non-cancelable. At the end of the initial term, OPCo can renew the lease, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.

On March 31, 2003, OPCo made a prepayment of $90 million under this lease structure. AEP recognizes lease expense on a straight-line basis over the remaining lease term, in accordance with SFAS 13 "Accounting for Leases." The asset will be amortized over the remaining lease term, which ends in the first quarter of 2010.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of our requirement to consolidate JMG, and there was no change in net income due to the consolidation of JMG. Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for on a consolidated basis as an operating lease and has been excluded from the above table of future minimum lease payments.

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee) an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors. The future minimum lease payments for each respective company are $1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt.

Railcar Lease

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms, for a maximum of twenty years. We intend to renew the lease for the full twenty years. At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease with the future payment included in the future minimum lease payments schedule earlier in this note. This operating lease agreement allows us to avoid a large initial capital expenditure, and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the term from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2003, the maximum potential loss was approximately $31.5 million ($20.5 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year to an unaffiliated company under an operating lease. The sublessee may renew the lease for up to four additional one-year terms. AEP has other rail car lease arrangements that do not utilize this type of structure.

17. FINANCING ACTIVITIES

Trust Preferred Securities

PSO, SWEPCo and TCC have wholly-owned business trusts that have issued trust preferred securities. The trusts which hold mandatorily redeemable trust preferred securities were deconsolidated effective July 1, 2003 due to the implementation of FIN 46. Therefore, $321 million ($75 million PSO, $110 million SWEPCo and $136 million TCC), previously reported at December 31, 2002 as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries, is now reported as two components on the Balance Sheet. The $10 million investment in the trust is now reported as Other within Other Non-Current Assets while the $331 million of subordinated debentures are now reported as Notes Payable to Trust within Long-term Debt.

The Junior Subordinated Debentures of PSO and TCC mature on April 30, 2037. In October 2003, SWEPCo refinanced its Junior Subordinated Debentures which are now due October 1, 2043. The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2003 and 2002:

Business Trust	Security	Units Issued/ Outstanding at 12/31/03	Amount in Other at 12/31/03 (a) (in millions)	Amount in Notes Payable to Trust at 12/31/03 (b) (in millions)	Amount Reported Prior to FIN 46 at 12/31/02 (c) (in millions)	Description of Underlying Debentures of Registrant
CPL Capital I	8.00%, Series A	5,450,000	$5	$141	$136	TCC, $141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	2	77	75	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	7.875%, Series A	-	-	-	110	SWEPCo, $113 million, 7.875%, Series A
SWEPCo Capital I	5.25%, Series B	110,000	3	113	-	SWEPCo, $113 million, 5.25% five year fixed rate period, Series B
Total		8,560,000	$10	$331	$321	

(a) Amounts are in Other within Other Non-Current Assets.
(b) Amounts are in Notes Payable to Trust within Long-term Debt.
(c) Amounts reported on Balance Sheet prior to FIN 46.

Each of the business trusts is treated as a non-consolidated 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.

Minority Interest in Finance Subsidiary

We formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis) in August 2001. SubOne is a wholly-owned consolidated subsidiary that was capitalized with the assets of Houston Pipe Line Company and Louisiana Intrastate Gas Company and $321.4 million of AEP Energy Services Gas Holding Company (AEP Gas Holding is a subsidiary of AEP and the parent of SubOne) preferred stock, that was convertible into AEP common stock at market price on a dollar-for-dollar basis. Caddis was capitalized with $2 million cash and a subscription agreement that represents an unconditional obligation to fund $83 million from SubOne for a managing member interest and $750 million from Steelhead Investors LLC (Steelhead) for a non-controlling preferred member interest. As managing member, SubOne consolidated Caddis. Steelhead is an unconsolidated special purpose entity and had an original capital structure of $750 million (currently approximately $525 million) of which 3% is equity from investors with no relationship to us or any of our subsidiaries and 97% is debt from a syndicate of banks. The $525 million invested in Caddis by Steelhead was loaned to SubOne. The loan to SubOne is due August 2006. Net proceeds from the proposed sale of LIG will be used to reduce the outstanding balance of the loan from Caddis (see Note 10 for additional information on LIG and HPL).

On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis, which included amounts previously reported as Minority Interest in Finance Subsidiary ($759 million at December 31, 2002 and $533 million at June 30, 2003). As a result, a note payable to Caddis is reported as a component of Long-term Debt ($527 million at December 31, 2003). Due to the prospective application of FIN 46, we did not change the presentation of Minority Interest in Finance Subsidiary in periods prior to July 1, 2003.

On May 9, 2003, SubOne borrowed $225 million from us and used the proceeds to reduce the outstanding balance of the loan from Caddis, which Caddis used to reduce the preferred interest held by Steelhead. This payment eliminated the convertible preferred stock of AEP Gas Holding which under certain conditions had been convertible to AEP common stock.

The credit agreement between Caddis and SubOne contains covenants that restrict certain incremental liens and indebtedness, asset sales, investments, acquisitions, and distributions. The credit agreement also contains covenants that impose minimum financial ratios. Non-performance of these covenants may result in an event of default under the credit agreement. Through December 31, 2003, SubOne has complied with the covenants contained in the credit agreement. In addition, the acceleration of outstanding debt in excess of $50 million would be an event of default under the credit agreement.

SubOne has deposited $422 million in a cash reserve fund in order to comply with certain covenants in the credit agreement. Pursuant to the terms of the credit agreement, SubOne subsequently loaned these funds to affiliates, and we guaranteed the repayment obligations of these affiliates. These loans must be repaid in the event our credit ratings fall below investment grade.

Steelhead has certain rights as a preferred member in Caddis. Upon the occurrence of certain events, including a default in the payment of the preferred return, Steelhead's rights include forcing a liquidation of Caddis and acting as the liquidator. Liquidation of Caddis could negatively impact our liquidity.

Caddis and SubOne are each a limited liability company, with a separate existence and identity from its members, and the assets of each are separate and legally distinct from us.

Equity Units

In June 2002, AEP issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consists of a forward purchase contract and a senior note.

The forward purchase contracts obligate the holders to purchase shares of AEP common stock on August 16, 2005. The purchase price per equity unit is $50. The number of shares to be purchased under the forward purchase contract will be determined under a formula based upon the average closing price of AEP common stock near the stock purchase date. Holders may satisfy their obligation to purchase AEP common stock under the forward purchase contracts by allowing the senior notes to be remarketed or by continuing to hold the senior notes and using other resources as consideration for the purchase of stock. If the holders elect to allow the notes to be remarketed, the proceeds from the remarketing will be used to purchase a portfolio of U.S. treasury securities that the holders will pledge to AEP in order to meet their obligations under the forward purchase contracts.

The senior notes have a principal amount of $50 each and mature on August 16, 2007. The senior notes are the collateral that secures the holders' requirement to purchase common stock under the forward purchase contracts.

AEP is making quarterly interest payments on the senior notes at an initial annual rate of 5.75%. The interest rate can be reset through a remarketing, which is initially scheduled for May 2005. AEP makes contract adjustment payments to the purchaser at the annual rate of 3.50% on the forward purchase contracts. The present value of the contract adjustment payments was recorded as a $31 million liability in Equity Unit Senior Notes offset by a charge to Paid-in Capital in June 2002. Interest payments on the senior notes are reported as interest expense. Accretion of the contract adjustment payment liability is reported as interest expense.

AEP applies the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contract are used to repurchase outstanding shares.

Lines of Credit – AEP System

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a utility money pool, which funds the utility subsidiaries, and a non-utility money pool, which funds the majority of the non-utility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. As of December 31, 2003, we had credit facilities totaling $2.9 billion to support our commercial paper program. At December 31, 2003, AEP had $326 million outstanding in short-term borrowings of which $282 million was commercial paper supported by the revolving credit facilities. In addition, JMG has commercial paper outstanding in the amount of $26 million. This commercial paper is specifically associated with the Gavin scrubber lease identified in Note 16 "Leases". This commercial paper does not reduce available liquidity to AEP. The maximum amount of commercial paper outstanding during the year, which had a weighted average interest rate during 2003 of 1.98%, was $1.5 billion during January 2003. On December 11, 2002, Moody's Investor Services placed AEP's Prime-2 short-term rating for commercial paper under review for possible downgrade. On January 24, 2003, Standard & Poor's Rating Services placed AEP's A-2 short-term rating for commercial paper under review for possible downgrade. On February 10, 2003, Moody's Investor Services downgraded AEP's short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poor's Rating Services reaffirmed AEP's A-2 short-term rating for commercial paper.

Outstanding Short-term Debt consisted of:

	December 31,	
	2003	**2002**
	(in millions)	
Balance Outstanding:		
Notes Payable	$18	$1,322
Commercial Paper - AEP	282	1,417
Commercial Paper - JMG	26	-
Total	$326	$2,739

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. We continue to service the receivables. We entered into this off-balance sheet transaction to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain registrant subsidiaries and, until the first quarter of 2002, with non-affiliated companies. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. As a result of the restructuring of electric utilities in the State of Texas, the purchase agreement between AEP Credit and Reliant

Energy, Incorporated was terminated as of January 25, 2002 and the purchase agreement between AEP Credit and Texas-New Mexico Power Company, the last remaining non-affiliated company, was terminated on February 7, 2002. In addition, the purchase agreements between AEP Credit and its Texas affiliates, AEP Texas Central Company (formerly Central Power and Light Company) and AEP Texas North Company (formerly West Texas Utilities Company), were terminated effective March 20, 2002.

Comparative accounts receivable information for AEP Credit:

	Year Ended December 31, 2003	Year Ended December 31, 2002
	(in millions)	
Proceeds from Sale of Accounts Receivable	$5,221	$5,513
Accounts Receivable Retained Interest Less Uncollectible Accounts and Amounts Pledged as Collateral	124	76
Deferred Revenue from Servicing Accounts Receivable	1	1
Loss on Sale of Accounts Receivable	7	4
Average Variable Discount Rate	1.33%	1.92%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	122	74
Retained Interest if 20% Adverse Change in Uncollectible Accounts	121	72

Historical loss and delinquency amount for the AEP System's customer accounts receivable managed portfolio:

	Face Value Year Ended December 31, 2003	Face Value Year Ended December 31, 2002
	(in millions)	
Customer Accounts Receivable Retained	$1,155	$1,553
Accrued Unbilled Revenues Retained	596	551
Miscellaneous Accounts Receivable Retained	83	93
Allowance for Uncollectible Accounts Retained	(124)	(108)
Total Net Balance Sheet Accounts Receivable	1,710	2,089
Customer Accounts Receivable Securitized (Affiliate)	385	454
Total Accounts Receivable Managed	$2,095	$2,543
Net Uncollectible Accounts Written Off	$39	$48

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

At December 31, 2003, delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors was $30 million.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

Our unaudited quarterly financial information is as follows:

	2003 Quarterly Periods Ended			
(In Millions – Except Per Share Amounts)	March 31	June 30	September 30	December 31
Revenues	$3,834	$3,451	$3,940	$3,320
Operating Income (Loss)	630	393	735	(126)
Income (Loss) Before Discontinued Operations, Extraordinary Items and Cumulative Effect	294	185	298	(255)
Net Income (Loss)	440	175	257	(762)
Earnings (Loss) per Share Before Discontinued Operations, Extraordinary Items and Cumulative Effect*	0.83	0.47	0.75	(0.65)
Earnings (Loss) per Share**	1.24	0.44	0.65	(1.93)

	2002 Quarterly Periods Ended			
(In Millions – Except Per Share Amounts)	March 31	June 30	September 30	December 31
Revenues	$2,802	$3,395	$3,639	$3,472
Operating Income	420	433	781	170
Income (Loss) Before Discontinued Operations, Extraordinary Items and Cumulative Effect	134	167	385	(201)
Net Income (Loss)	(169)	62	425	(837)
Earnings (Loss) per Share Before Discontinued Operations, Extraordinary Items and Cumulative Effect***	0.42	0.51	1.14	(0.59)
Earnings (Loss) per Share****	(0.53)	0.19	1.25	(2.47)

* Amounts for 2003 do not add to $1.35 earnings per share before Discontinued Operations, Extraordinary Loss and Cumulative Effect due to rounding and the dilutive effect of shares issued in 2003.
** Amounts for 2003 do not add to $0.29 earnings per share due to rounding and the dilutive effect of shares issued in 2003.
***Amounts for 2002 do not add to $1.46 earnings per share before Discontinued Operations, Extraordinary Loss and Cumulative Effect due to rounding.
****Amounts for 2002 do not add to $(1.57) earnings per share due to rounding.

Income (Loss) Before Discontinued Operations, Extraordinary Items and Cumulative Effect for the fourth quarter 2003 ($255 million loss) and 2002 ($201 million loss) were significantly lower than the previous three quarters due to asset impairments, investment value losses and other related charges. These pre-tax writedowns ($650 million in the fourth quarter 2003 and $593 million in the fourth quarter 2002) were made to reflect impairments and discontinued operations as discussed in Note 10.

19. SUBSEQUENT EVENTS (UNAUDITED)

After December 31, 2003, we entered into separate agreements to dispose of the following investments:

Investment	Sales Price (in millions)	Date of Agreement
Oklaunion Power Station	$42.8	January 30, 2004
LIG Pipeline and its subsidiaries	$76.2	February 13, 2004
STP	$332.6	February 27, 2004

We anticipate these sales to be completed during 2004 and that the impact on results of operations will not be significant.

The Nanyang General Light (Pushan) investment was sold for $60.7 million on March 2, 2004. This sale had no significant impact on our results of operations.

On March 10, 2004, we entered into an agreement to sell four domestic Independent Power Producer (IPP) investments for a sales price of $156 million. We anticipate this sale to be completed during 2004 and to result in a pre-tax gain of approximately $100 million.

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2003 and 2002, and the related consolidated statements of operations, cash flows and common shareholders' equity and comprehensive income, for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 142, "Goodwill and Other Intangible Assets," effective January 1, 2002.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations" and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" effective January 1, 2003.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities" effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

MANAGEMENT'S RESPONSIBILITY

The management of American Electric Power Company, Inc. (the Company) has prepared the financial statements and schedules herein and 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 United States of America, 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 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 financial statements have been audited by Deloitte & Touche LLP, whose report appears on the previous page.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2003	2002	2001	2000	1999
			(in thousands)		
INCOME STATEMENTS DATA					
Operating Revenues	$1,595,596	$1,526,764	$1,526,997	$1,488,209	$1,351,666
Operating Expenses	1,409,529	1,375,575	1,367,292	1,522,911	1,243,014
Operating Income (Loss)	186,067	151,189	159,705	(34,702)	108,652
Nonoperating Items, Net	(13,465)	16,726	9,730	9,933	4,530
Interest Charges	83,054	93,923	93,647	107,263	80,406
Net Income (Loss) Before Cumulative Effect of Accounting Change	89,548	73,992	75,788	(132,032)	32,776
Cumulative Effect of Accounting Change (Net of Tax)	(3,160)	-	-	-	-
Net Income (Loss)	86,388	73,992	75,788	(132,032)	32,776
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	2,509	4,601	4,621	4,624	4,885
Earnings (Loss) Applicable to Common Stock	$83,879	$69,391	$71,167	$(136,656)	$27,891
BALANCE SHEETS DATA					
Electric Utility Plant	$5,306,182	$5,029,958	$4,923,721	$4,871,473	$4,770,027
Accumulated Depreciation and Amortization	2,490,912	2,318,063	2,198,524	2,057,542	1,981,430
Net Electric Utility Plant	$2,815,270	$2,711,895	$2,725,197	$2,813,931	$2,788,597
TOTAL ASSETS	$4,659,071	$4,837,732	$4,632,510	$5,997,087	$4,788,177
Common Stock and Paid-in Capital	$915,278	$915,144	$789,800	$789,656	$789,323
Retained Earnings	187,875	143,996	74,605	3,443	166,389
Accumulated Other Comprehensive Income (Loss)	(25,106)	(40,487)	(3,835)	-	-
Total Common Shareholder's Equity	$1,078,047	$1,018,653	$860,570	$793,099	$955,712
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$8,101	$8,101	$8,736	$8,736	$9,248
Subject to Mandatory Redemption (a)	63,445	64,945	64,945	64,945	64,945
Total Cumulative Preferred Stock	$71,546	$73,046	$73,681	$73,681	$74,193
Long-term Debt (a)	$1,339,359	$1,617,062	$1,652,082	$1,388,939	$1,324,326
Obligations Under Capital Leases (a)	$37,843	$50,848	$61,933	$163,173	$187,965
TOTAL CAPITALIZATION AND LIABILITIES	$4,659,071	$4,837,732	$4,632,510	$5,997,087	$4,788,177

(a) Including portion due within one year.

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 575,000 retail customers in our service territory in northern and eastern Indiana and a portion of southwestern Michigan. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities and electric cooperatives.

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

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

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

During 2003, Net Income increased $12 million including an unfavorable $3 million Cumulative Effect of Accounting Change (see Note 2). During 2003, Net Income Before Cumulative Effect of Accounting Change increased $15 million due to reduced financing costs and an improvement in Operating Income resulting from higher margins on wholesale sales and lower Other Operation expense.

During 2002, Net Income decreased by $2 million due to increased operations and maintenance costs incurred as part of planned and unplanned outages at Cook and Rockport plants.

2003 Compared to 2002

Operating Income

Operating Income increased $35 million primarily due to:

- Increased wholesale sales of $69 million including system and power optimization sales, transmission revenues and risk management activities reflecting availability of AEP's generation and market conditions.
- Increased Sales to AEP Affiliates of $35 million due to increased capacity revenue.
- Decreased Other Operations expense of $45 million due primarily to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits of $15 million recorded in 2002.

The increase in Operating Income was partially offset by:

- Decreased retail revenues of $37 million due primarily to milder summer weather and economic pressures on industrial customers. Cooling degree days declined approximately 42% this year compared with last year. Industrial revenues dropped 3% from prior year.
- Increased Fuel for Electric Generation expense of $11 million reflecting an increase in the average cost of fuel and increased coal-fired generation in 2003 as Rockport's availability increased.
- Increased Purchased Electricity from AEP Affiliates of $41 million due to purchasing more power from the AEP Power Pool to support wholesale sales to unaffiliated entities.
- Increased Income Tax expense of $12 million reflecting an increase in pre-tax operating income partially offset by temporary differences accounted for on a flow-through basis and tax return adjustments.

Other Impacts on Earnings

Nonoperating Income decreased $30 million primarily due to lower margins for power sold outside of AEP's traditional market reflecting AEP's plan to exit those risk management activities.

Nonoperating Expenses increased $16 million primarily due to a $10 million write-down of western coal lands (see Note 10).

Nonoperating Income Taxes decreased $16 million reflecting the decrease in pre-tax nonoperating income.

Interest Charges decreased $11 million primarily due to a reduction in outstanding long-term debt of $255 million which was retired in May 2003 using lower rate short-term debt.

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change is due to the implementation of the requirements of EITF 02-3 (see Note 2).

<u>2002 Compared to 2001</u>

Operating Income

Operating Income decreased $9 million primarily due to:

- Decreased Sales to AEP Affiliates of $41 million reflecting less energy to sell due to outages. In 2002, both units of Cook plant were shut down for refueling and both Rockport units were down for planned boiler maintenance.
- Increased Other Operation expense of $14 million due to increased costs for pensions, insurance and other benefits.
- Increased Maintenance expense of $24 million reflecting two nuclear refueling outages in 2002.

The decrease in Operating Income was partially offset by:

- Increased Retail revenues of $35 million reflecting a 4% increase in sales.
- Decreased Fuel for Electric Generation expense of $11 million reflecting a decline in the average cost of fuel and decreased nuclear generation.
- An $8 million decrease in Taxes Other Than Income Taxes reflects a favorable tax law change in Indiana effective March 2002.
- Decreased Income Taxes of $15 million reflecting a decrease in pre-tax operating income.

Other Impacts on Earnings

Nonoperating Expenses decreased $10 million due to a decrease in trading overheads and traders' incentive compensation.

Financial Condition

Credit Ratings

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

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

During the first quarter of 2003, Moody's Investors Service (Moody's), Standard & Poors (S&P) and Fitch Rating Service completed their reviews of AEP and its rated subsidiaries. The reviews resulted in downgrades of debt ratings. The completion of these reviews was a culmination of ratings action started during 2002.

Cash Flow

Cash flows for 2003, 2002 and 2001 were as follows:

	2003	2002	2001
		(in thousands)	
Cash and cash equivalents at beginning of period	$3,237	$16,804	$14,835
Cash flow from (used for):			
Operating activities	222,773	228,234	236,207
Investing activities	(182,703)	(165,725)	(182,594)
Financing activities	(39,393)	(76,076)	(51,644)
Net increase (decrease) in cash and cash equivalents	677	(13,567)	1,969
Cash and cash equivalents at end of period	$3,914	$3,237	$16,804

Operating Activities

Operating activities during 2003 provided $5 million less cash than during 2002 which was $8 million less than during 2001 largely due to working capital requirements and changes in mark-to-market of risk management contracts.

Investing Activities

Cash flows used for investing activities during 2003 were $183 million compared to $166 million during 2002. The primary reason for the year-over-year variance was increased construction expenditures of $17 million. Construction expenditures increased $76 million comparing 2002 with 2001. In 2001, we bought out nuclear fuel leases using $93 million of operating cash. Construction expenditures for the nuclear plant and transmission and distribution assets are to upgrade or replace equipment and improve reliability.

Financing Activities

Financing activities for 2003 used $39 million of cash from operations primarily to pay common dividends. During 2003, we redeemed $285 million of long-term debt using short-term debt and refinanced $65 million of our installment purchase contracts at lower fixed rates until October 2006.

During 2002, we redeemed $340 million of long-term debt and $145 million of short-term debt using cash from operations, a $125 million capital contribution from our parent company and proceeds from the issuance of $300 million of long-term debt.

During 2001, we issued $300 million of long-term debt to reduce short-term debt.

Financing Activity

Long-term debt issuances and retirements during 2003 were:

Issuances

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Installment Purchase Contracts	$25	2.625(a)	2019
Installment Purchase Contracts	40	2.625(a)	2025

(a) Fixed Until October 1, 2006

Retirements

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
First Mortgage Bonds	$30	6.10	2003
First Mortgage Bonds	75	8.50	2022
First Mortgage Bonds	15	7.35	2023
Junior Debentures	40	8.00	2026
Junior Debentures	125	7.60	2038
Installment Purchase Contracts	25	7.00	2015
Installment Purchase Contracts	40	7.60	2016

Off-Balance Sheet Arrangements

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

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each respective company are $1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in millions)				
Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt	$205	$365	$100	$669	$1,339
Advances from Affiliates	99	-	-	-	99
Preferred Stock Subject to Mandatory Redemption	-	-	16	47	63
Capital Lease Obligations	10	14	16	6	46
Unconditional Purchase Obligations (a)	107	89	82	161	439
Noncancellable Operating Leases	104	191	182	1,097	1,574
Total	$525	$659	$396	$1,980	$3,560

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Some of the transactions, described under "Off-Balance Sheet Arrangements" above, have been employed for a contractual cash obligation reported in the above table. The lease of Rockport Unit 2 is reported in Noncancellable Operating Leases.

Significant Factors

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

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$70,861
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(18,666)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	88
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(4,861)
Changes in Fair Value of Risk Management Contracts (e)	765
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	(6,192)
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	41,995
Net Cash Flow Hedge Contracts (g)	341
DETM Assignment (h)	(19,932)
Ending Balance December 31, 2003	$22,404

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.

(b) The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c)"Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.

(d) See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."

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

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

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

(h)See Note 17 "Related Party Transactions."

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

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

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

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted – Exchange Traded Contracts	$753	$(151)	$18	$118	$-	$-	$738
Prices Provided by Other External Sources – OTC Broker Quotes (a)	14,786	5,256	5,154	2,095	1,051	-	28,342
Prices Based on Models and Other Valuation Methods (b)	(151)	23	2,045	2,364	2,174	6,460	12,915
Total	$15,388	$5,128	$7,217	$4,577	$3,225	$6,460	$41,995

(a) "Prices Provided by Other External Sources" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	$(286)
Changes in Fair Value (a)	209
Reclassifications from AOCI to Net Income (b)	299
Ending Balance December 31, 2003	$222

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,031 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$368	$1,429	$598	$142	$927	$2,840	$1,016	$206

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $79 million and $85 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$1,346,393	$1,312,626	$1,271,958
Sales to AEP Affiliates	249,203	214,138	255,039
TOTAL	1,595,596	1,526,764	1,526,997
OPERATING EXPENSES			
Fuel for Electric Generation	250,890	239,455	250,098
Purchased Electricity for Resale	28,327	23,443	18,707
Purchased Electricity from AEP Affiliates	274,400	233,724	238,237
Other Operation	417,636	462,707	449,115
Maintenance	158,281	151,602	127,263
Depreciation and Amortization	171,281	168,070	164,230
Taxes Other Than Income Taxes	57,788	57,721	65,518
Income Taxes	50,926	38,853	54,124
TOTAL	1,409,529	1,375,575	1,367,292
OPERATING INCOME	186,067	151,189	159,705
Nonoperating Income	53,928	84,084	85,673
Nonoperating Expenses	77,171	61,374	70,900
Nonoperating Income Tax Expense (Credit)	(9,778)	5,984	5,043
Interest Charges	83,054	93,923	93,647
Net Income Before Cumulative Effect of Accounting Change	89,548	73,992	75,788
Cumulative Effect of Accounting Change (Net of Tax)	(3,160)	-	-
NET INCOME	86,388	73,992	75,788
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	2,509	4,601	4,621
EARNINGS APPLICABLE TO COMMON STOCK	$83,879	$69,391	$71,167

The common stock of I&M is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$56,584	$733,072	$3,443	$-	$793,099
Preferred Stock Dividends			(4,487)		(4,487)
Capital Stock Expense		144	(139)		5
					788,617
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Interest Rate Hedge				(3,835)	(3,835)
NET INCOME			75,788		75,788
TOTAL COMPREHENSIVE INCOME					71,953
DECEMBER 31, 2001	$56,584	$733,216	$74,605	$(3,835)	$860,570
Capital Contributions from Parent Company		125,000			125,000
Preferred Stock Dividends			(4,467)		(4,467)
Capital Stock Expense		344	(134)		210
					981,313
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Interest Rate Hedge				3,835	3,835
Unrealized Loss on Cash Flow Power Hedges				(286)	(286)
Minimum Pension Liability				(40,201)	(40,201)
NET INCOME			73,992		73,992
TOTAL COMPREHENSIVE INCOME					37,340
DECEMBER 31, 2002	$56,584	$858,560	$143,996	$(40,487)	$1,018,653
Common Stock Dividends			(40,000)		(40,000)
Preferred Stock Dividends			(2,375)		(2,375)
Capital Stock Expense		134	(134)		-
					976,278
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				508	508
Minimum Pension Liability				14,873	14,873
NET INCOME			86,388		86,388
TOTAL COMPREHENSIVE INCOME					101,769
DECEMBER 31, 2003	$56,584	$858,694	$187,875	$(25,106)	$1,078,047

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,878,051	$2,768,463
Transmission	1,000,926	971,599
Distribution	958,966	921,835
General (including nuclear fuel)	274,283	220,137
Construction Work in Progress	193,956	147,924
TOTAL	5,306,182	5,029,958
Accumulated Depreciation and Amortization	2,490,912	2,318,063
TOTAL - NET	2,815,270	2,711,895
OTHER PROPERTY AND INVESTMENTS		
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	982,394	870,754
Non-Utility Property, Net	52,303	69,252
Other Investments	43,797	51,689
TOTAL	1,078,494	991,695
CURRENT ASSETS		
Cash and Cash Equivalents	3,914	3,237
Advances to Affiliates	-	191,226
Accounts Receivable:		
Customers	61,084	92,929
Affiliated Companies	124,826	122,489
Accrued Unbilled Revenues	2,000	6,511
Miscellaneous	4,498	4,872
Allowance for Uncollectible Accounts	(531)	(578)
Fuel	33,968	32,731
Materials and Supplies	105,328	95,552
Risk Management Assets	44,071	67,985
Margin Deposits	7,245	890
Prepayments and Other	10,673	11,172
TOTAL	397,076	629,016
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	151,973	163,928
Deferred Fuel Costs	-	37,501
Cook Plant Restart Costs	-	40,000
Incremental Nuclear Refueling Outage Expenses, Net	57,326	29,572
Other	66,978	77,211
Long-term Risk Management Assets	43,768	83,265
Deferred Property Taxes	21,916	22,271
Deferred Charges and Other Assets	26,270	51,378
TOTAL	368,231	505,126
TOTAL ASSETS	$4,659,071	$4,837,732

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	$56,584	$56,584
Paid-in Capital	858,694	858,560
Retained Earnings	187,875	143,996
Accumulated Other Comprehensive Income (Loss)	(25,106)	(40,487)
Total Common Shareholder's Equity	1,078,047	1,018,653
Cumulative Preferred Stock – Not Subject to Mandatory Redemption	8,101	8,101
Total Shareholder's Equity	1,086,148	1,026,754
Liability for Cumulative Preferred Stock - Subject to Mandatory Redemption	63,445	64,945
Long-term Debt	1,134,359	1,587,062
TOTAL	2,283,952	2,678,761
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	205,000	30,000
Advances from Affiliates	98,822	-
Accounts Payable:		
General	101,776	125,048
Affiliated Companies	47,484	93,608
Customer Deposits	21,955	16,660
Taxes Accrued	42,189	71,559
Interest Accrued	17,963	21,481
Risk Management Liabilities	31,898	48,568
Obligations Under Capital Leases	6,528	8,229
Other	57,675	76,162
TOTAL	631,290	491,315
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	337,376	356,197
Regulatory Liabilities:		
Asset Removal Costs	263,015	-
Deferred Investment Tax Credits	90,278	97,709
Excess ARO for Nuclear Decommissioning	215,715	-
Other	61,268	65,983
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	70,179	73,885
Long-term Risk Management Liabilities	33,537	32,261
Obligations Under Capital Leases	31,315	42,619
Asset Retirement Obligations	553,219	-
Nuclear Decommissioning	-	620,672
Deferred Credits and Other	87,927	378,330
TOTAL	1,743,829	1,667,656
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$4,659,071	$4,837,732

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING ACTIVITIES			
Net Income	$86,388	$73,992	$75,788
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Impairments	10,300	-	-
Cumulative Effect of Accounting Change	3,160	-	-
Depreciation and Amortization	171,281	168,070	166,360
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(27,754)	(26,577)	418
Unrecovered Fuel and Purchased Power Costs	37,501	37,501	37,501
Amortization of Nuclear Outage Costs	40,000	40,000	40,000
Deferred Income Taxes	(14,894)	(16,921)	(29,205)
Deferred Investment Tax Credits	(7,431)	(7,740)	(8,324)
Mark-to-Market of Risk Management Contracts	43,938	(9,517)	(62,647)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	34,346	(106,683)	62,769
Fuel, Materials and Supplies	(11,013)	(7,854)	(19,426)
Accounts Payable	(69,396)	87,934	(60,185)
Taxes Accrued	(29,370)	1,798	1,345
Change in Other Assets	(24,302)	(29,264)	2,622
Change in Other Liabilities	(19,981)	23,495	29,191
Net Cash Flows From Operating Activities	222,773	228,234	236,207
INVESTING ACTIVITIES			
Construction Expenditures	(184,188)	(167,484)	(91,052)
Buyout of Nuclear Fuel Leases	-	-	(92,616)
Other	1,485	1,759	1,074
Net Cash Flows Used For Investing Activities	(182,703)	(165,725)	(182,594)
FINANCING ACTIVITIES			
Capital Contributions from Parent	-	125,000	-
Issuance of Long-term Debt	64,434	288,732	297,656
Retirement of Cumulative Preferred Stock	(1,500)	(424)	-
Retirement of Long-term Debt	(350,000)	(340,000)	(44,922)
Change in Advances to/from Affiliates, Net	290,048	(144,917)	(299,891)
Dividends Paid on Common Stock	(40,000)	-	-
Dividends Paid on Cumulative Preferred Stock	(2,375)	(4,467)	(4,487)
Net Cash Flows Used For Financing Activities	(39,393)	(76,076)	(51,644)
Net Increase (Decrease) in Cash and Cash Equivalents	677	(13,567)	1,969
Cash and Cash Equivalents at Beginning of Period	3,237	16,804	14,835
Cash and Cash Equivalents at End of Period	$3,914	$3,237	$16,804

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $82,593,000, $89,984,000 and $92,140,000 and for income taxes was $94,440,000, $60,523,000 and $100,470,000 in 2003, 2002 and 2001, respectively. Non-cash acquisitions under capital leases were $1,023,000 and $22,218,000 in 2002 and 2001, respectively. There were no non-cash capital lease acquisitions in 2003.

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

Series	Call Price December 31, 2003 (a)	Number of Shares Redeemed Year Ended December 31, 2003	2002	2001	Shares Outstanding December 31, 2003	2003 (in thousands)	2002 (in thousands)
COMMON SHAREHOLDER'S EQUITY						$1,078,047	$1,018,653
PREFERRED STOCK:							
$100 Par Value - Authorized 2,250,000 shares							
$25 Par Value - Authorized 11,200,000 shares							
Not Subject to Mandatory Redemption - $100 Par:							
4-1/8%	106.125	-	20	-	55,369	5,537	5,537
4.56%	102	-	-	-	14,412	1,441	1,441
4.12%	102.728	-	6,326	-	11,230	1,123	1,123
Total						8,101	8,101
Subject to Mandatory Redemption - $100 Par(b):							
5.90% (c)		-	-	-	152,000	15,200	15,200
6-1/4% (c)		-	-	-	192,500	19,250	19,250
6.30% (c)		-	-	-	132,450	13,245	13,245
6-7/8% (d)		15,000	-	-	157,500	15,750	17,250
Total						63,445	64,945
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						54,725	174,245
Installment Purchase Contracts						310,676	310,336
Senior Unsecured Notes						747,873	747,027
Other Long-term Debt (e)						226,085	223,736
Junior Debentures						-	161,718
Less Portion Due Within One Year						(205,000)	(30,000)
Long-term Debt Excluding Portion Due Within One Year						1,134,359	1,587,062
TOTAL CAPITALIZATION						$2,283,952	$2,678,761

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
(b) Sinking fund provisions require the redemption of 67,500 shares in each of 2004, 2005, 2006 and 2007 and 52,500 shares in 2008. The sinking fund provisions of each series subject to mandatory redemption have been met by purchase of shares in advance of these due dates. Shares previously purchased may be applied to meet the sinking fund requirement.
(c) Commencing in 2004 and continuing through 2008 I&M may redeem, at $100 per share, 20,000 shares of the 5.90% series, 15,000 shares of the 6-1/4% series and 17,500 shares of the 6.30% series outstanding under sinking fund provisions at its option and all remaining outstanding shares must be redeemed not later than 2009. The series are callable beginning November 1, 2003 for the 5.90% series, December 1, 2003 for the 6-1/4% series and March 1, 2004 for the 6.30% series at $100 plus accrued dividends.
(d) Commencing in 2003 and continuing through the year 2007, a sinking fund will require the redemption of 15,000 shares each year and the redemption of the remaining shares outstanding on April 1, 2008, in each case at $100 per share. Callable at $100 per share plus accrued dividends beginning February 1, 2003.
(e) Represents a liability for SNF disposal including interest payable to the DOE. See Note 7.

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.10	2003 – November 1	$-	$30,000
8.50	2022 – December 15	-	75,000
7.35	2023 – October 1	-	15,000
7.20	2024 – February 1	30,000 (a)	30,000
7.50	2024 – March 1	25,000 (a)	25,000
Unamortized Discount		(275)	(755)
Total		$54,725	$174,245

(a) These bonds will be redeemed in April 2004 and have been classified for payment in 2004.

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. Certain supplemental indentures to the first mortgage lien contain maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

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

	% Rate	Due	2003	2002
			(in thousands)	
City of Lawrenceburg, Indiana:				
	7.00	2015 – April 1	$-	$25,000
	(a)	2019 – October 1	25,000	-
	5.90	2019 – November 1	52,000	52,000
City of Rockport, Indiana:				
	7.60	2016 – March 1	-	40,000
	(a)	2025 – April 1	40,000	-
	6.55	2025 – June 1	50,000	50,000
	(b)	2025 – June 1	50,000	50,000
	4.90(c)	2025 – June 1	50,000	50,000
City of Sullivan, Indiana:				
	5.95	2009 – May 1	45,000	45,000
	Unamortized Discount		(1,324)	(1,664)
	Total		$310,676	$310,336

(a) Rate is an annual long-term fixed rate of 2.625% through October 1, 2006. After that date the rate may be a daily or weekly reset rate, commercial paper, auction or other long-term rate as designated by I&M (fixed rate bonds).
(b) In 2001, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate for 2003 ranged from 0.85% to 1.35% and averaged 1.05%. The auction rate for 2002 ranged from 1.3% to 1.7% and averaged 1.5%.
(c) Rate is fixed until June 1, 2007 (term rate bonds).

The terms of the installment purchase contracts require I&M to pay amounts sufficient for the cities to pay interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain generating plants. The fixed rate bonds due 2019 and 2025 are subject to mandatory tender for purchase on October 1, 2006. Consequently, the fixed rate bonds have been classified for repayment purposes in 2006. The term rate bonds due 2025 are subject to mandatory tender for purchase on the term maturity date (June 1, 2007). Accordingly, the term rate bonds have been classified for repayment purposes in 2007 (the term end date). Interest payments range from every 35 days to semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6-7/8	2004 – July 1	$150,000	$150,000
6.125	2006 – December 15	300,000	300,000
6.45	2008 – November 10	50,000	50,000
6.375	2012 – November 1	100,000	100,000
6.00	2032 – December 31	150,000	150,000
Unamortized Discount		(2,127)	(2,973)
Total		$747,873	$747,027

Junior Debentures outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
8.00	2026 – March 31	$-	$40,000
7.60	2038 – June 30	-	125,000
Unamortized Discount		-	(3,282)
Total		$ -	$161,718

At December 31, 2003 future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$205,000
2005	-
2006	365,000
2007	50,000
2008	50,000
Later Years	673,085
Total Principal Amount	1,343,085
Unamortized Discount	(3,726)
Total	$1,339,359

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to I&M's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to I&M. The footnotes begin on page L-1.

	Footnote Reference
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Customer Choice and Industry Restructuring	Note 6
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Indiana Michigan Power Company and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and subsidiaries as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations" and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

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NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to respective financial statements that follow are a combined presentation for AEP's subsidiary registrants. The following list indicates the registrants to which the footnotes apply:

1.	Organization and Summary of Significant Accounting Policies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3.	Goodwill and Other Intangible Assets	SWEPCo
4.	Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
5.	Effects of Regulation	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
6.	Customer Choice and Industry Restructuring	APCo, CSPCo, I&M, OPCo, SWEPCo, TCC, TNC
7.	Commitments and Contingencies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
8.	Guarantees	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
9.	Sustained Earnings Improvement Initiative	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	APCo, CSPCo, I&M, KPCo, OPCo, SWEPCo, TCC, TNC
11.	Benefit Plans	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
12.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
13.	Derivatives, Hedging and Financial Instruments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
14.	Income Taxes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
15.	Leases	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
16.	Financing Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
17.	Related Party Transactions	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
18.	Jointly Owned Electric Utility Plant	CSPCo, PSO, SWEPCo, TCC, TNC
19.	Unaudited Quarterly Financial Information	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
20.	Subsequent Events (Unaudited)	TCC

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by AEP's ten domestic electric utility operating companies is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

With the exception of AEGCo, AEP's registrant subsidiaries engage in wholesale marketing and risk management activities in the United States. In addition, I&M provides barging services to both affiliated and nonaffiliated companies.

See Note 10 for additional information regarding asset impairments and assets and liabilities held for sale related to our Texas generation plants.

Certain previously reported amounts have been reclassified to conform to current classifications with no effect on net income or shareholders' equity.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

AEP and its subsidiaries are subject to regulation by the SEC under the PUHCA. The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail rates.

Principles of Consolidation

The consolidated financial statements for APCo, CSPCo, I&M, OPCO, SWEPCo and TCC include the registrant and its wholly-owned subsidiaries and/or substantially controlled variable interest entities. Intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Nonoperating Income.

Accounting for the Effects of Cost-Based Regulation

As cost-based rate-regulated electric public utility companies, the 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. Regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues. The following subsidiaries discontinued the application of SFAS 71 for the generation portion of their business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by TCC, TNC, and SWEPCo in September 1999, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December 2003. During 2003, APCo reapplied SFAS 71 for West Virginia and SWEPCo reapplied SFAS 71 for Arkansas.

Use of Estimates

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

Property, Plant and Equipment

Domestic electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the non-regulated operations and other investments are stated at their fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are deducted from accumulated depreciation. For non-regulated operations, retirements from the plant accounts and associated salvage are deducted from accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses. Assets are tested for impairment as required under SFAS 144 (see Note 10).

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For non-regulated operations, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." Capitalized interest is also recorded for domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting. The amounts of AFUDC and interest capitalized were not material in 2003, 2002 and 2001.

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment on a straight-line basis over the estimated useful lives of property, excluding coal-mining properties, through the use of composite rates by functional class. The following table provides the annual composite depreciation rates by functional class generally used by the AEP registrant subsidiaries for the year 2003:

	Nuclear	Steam	Hydro	Transmission	Distribution	General
AEGCo	-%	3.5%	-%	-%	-%	16.7%
APCo	-	3.3	2.7	2.2	3.3	9.3
CSPCo	-	3.0	-	2.3	3.6	9.9
I&M	3.4	4.6	3.4	1.9	4.2	11.8
KPCo	-	3.8	-	1.7	3.5	7.1
OPCo	-	2.8	2.7	2.3	4.0	10.5
PSO	-	2.7	-	2.3	3.4	9.7
SWEPCo	-	3.3	-	2.8	3.6	8.0
TCC	2.5	2.3	1.9	2.3	3.5	8.1
TNC	-	2.6	-	3.1	3.3	10.2

The annual composite depreciation rates by functional class generally used by the AEP registrant subsidiaries for the years 2002 and 2001 were as follows:

	Nuclear	Steam	Hydro	Transmission	Distribution	General
AEGCo	-%	3.5%	-%	-%	-%	2.8%
APCo	-	3.4	2.9	2.2	3.3	3.1
CSPCo	-	3.2	-	2.3	3.6	3.2
I&M	3.4	4.5	3.4	1.9	4.2	3.8
KPCo	-	3.8	-	1.7	3.5	2.5
OPCo	-	3.4	2.7	2.3	4.0	2.7
PSO	-	2.7	-	2.3	3.4	6.3
SWEPCo	-	3.4	-	2.7	3.6	4.7
TCC	2.5	2.6	1.9	2.3	3.5	4.0
TNC	-	2.8	-	3.1	3.3	6.8

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs related to SWEPCo were $0.41 per ton in 2003, 2002 and 2001 and related to OPCo were $3.46 per ton in 2001. In 2001, OPCo sold coal mines in Ohio and West Virginia.

Valuation of Non-Derivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability for I&M approximates the best estimate of its fair value.

Cash and Cash Equivalents

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

Inventory

Except for PSO, TCC and TNC, the regulated domestic utility companies value fossil fuel inventories using a weighted average cost method. PSO, TCC and TNC, utilize the LIFO method to value fossil fuel inventories. For those domestic utilities whose generation is unregulated, inventory of coal and oil is carried at the lower of cost or market. Coal mine inventories are also carried at the lower of cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily includes receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, AEP and its registrant subsidiaries accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the latest billings.

AEP Credit, Inc. factors accounts receivable for certain registrant subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of the company's balance sheet. See Note 16 for further details.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amounts of over-recovery or under-recovery can also be affected by actions of regulators. When these actions become probable we adjust our deferrals to recognize these probable outcomes. For the Texas companies, TCC & TNC, their deferred fuel balances will be included in their 2004 True Up Proceeding (see Note 6 "Customer Choice and Industry Restructuring"). See Note 5 "Effects of Regulation" for the amount of deferred fuel costs by registrant subsidiary.

In general, changes in fuel costs in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo are timely reflected in rates through the fuel cost adjustment clauses in place in those states. Where fuel clauses have been eliminated due to the transition to market pricing, (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002) changes in fuel costs impact earnings. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes have also impacted earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze is scheduled to end on March 1, 2004. See Note 4, "Rate Matters" and Note 6, "Customer Choice and Industry Restructuring" for further information about fuel recovery.

Revenue Recognition

Regulatory Accounting

The consolidated financial statements of the registrant subsidiary companies with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo), reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers through regulated revenues in the same accounting period. Regulatory liabilities (unrealized gains) or regulatory assets (unrealized losses) are also recorded for changes in the fair value of physical and financial contracts that meet the definition of a derivative as defined in SFAS 133 and are subject to the regulated ratemaking process.

When regulatory assets are probable of recovery through regulated rates, certain registrant subsidiaries record them as assets on the balance sheet. Registrant subsidiaries test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If registrant subsidiaries determine that recovery of a regulatory asset is no longer probable, they write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized and recorded when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Energy Marketing and Risk Management Activities

Registrant subsidiaries engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in October 2002, these activities were focused on wholesale markets where registrant subsidiaries own assets. Registrant subsidiaries activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, registrant subsidiaries recorded wholesale marketing and risk management activities using the mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. Registrant subsidiaries implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into prior to October 25, 2002, registrant subsidiaries implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change.

After January 1, 2003, registrant subsidiaries use mark-to-market accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and rescission of EITF 98-10 in Note 2.

All of the registrant subsidiaries except AEGCo participate in wholesale marketing and risk management activities in electricity and gas. For I&M, KPCo, PSO and a portion of TNC and SWEPCo, when the contract settles the total gain or loss is realized in revenues. Where the revenues are recorded on the income statement depends on whether the contract is subject to the regulated ratemaking process. For contracts subject to the regulated ratemaking process the total gain or loss realized for sales and the cost of purchased energy are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts subject to the regulated ratemaking process are deferred as regulatory liabilities (gains) or regulatory assets (losses). For contracts not subject to the ratemaking process only the difference between the accumulated unrealized net gains or losses recorded in prior periods and the cash proceeds are recognized in the income statement as nonoperating income. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts not subject to the ratemaking process are included in nonoperating income on a net basis. Unrealized mark-to-market gains and losses are included in the balance sheets as Risk Management Assets or Liabilities as appropriate.

For APCo, CSPCo and OPCo, depending on whether the delivery point for the electricity is in the traditional marketing area or not determines where the contract is reported in the income statement. Physical forward risk management sale and purchase contracts with delivery points in the traditional marketing area are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in the traditional marketing area are also included in revenues on a net basis. Physical forward sale and purchase contracts for delivery outside of the traditional marketing area are included in nonoperating income when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of the traditional marketing area are included in nonoperating income on a net basis.

Accounting for Derivative Instruments

For derivative contracts that are not designated as hedges or normal purchase and sale transactions registrant subsidiaries recognize unrealized gains and losses prior to settlement based on changes in fair value during the period in our results of operations. When registrant subsidiaries settle mark-to-market derivative contracts and realize gains and losses, registrant subsidiaries reverse previously recorded unrealized gains and losses from mark-to-market valuations.

Certain derivative instruments are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the Consolidated Statement of Operations in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income and subsequently reclassified into Revenues in the Consolidated Statement of Operations when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the Consolidated Statement of Operations immediately (see Note 13).

Registrant subsidiaries measure the fair values of derivative instruments and hedge instruments accounted for using mark-to-market accounting based on exchange prices and broker quotes. If a quoted market price is not available, registrant subsidiaries estimate the fair value based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Registrant subsidiaries reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. There are inherent risks related to the underlying assumptions in models used to fair value open long-term derivative contracts. Registrant subsidiaries have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Registrant subsidiaries recognize all derivative instruments at fair value in our balance sheets as either Risk Management Assets or Risk Management Liabilities. Registrant subsidiaries do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in revenues in the income statement on a net basis.

Debt Instrument Hedging and Related Activities

In order to mitigate the risks of market price and interest rate fluctuations, registrant subsidiaries enter into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory hedges 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, 2003 or 2002.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with regulated revenues, 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.

Maintenance Costs

Maintenance costs are expensed as incurred. If it becomes probable that registrant subsidiaries will recover specifically incurred costs through future rates a regulatory asset is established to match the expensing of maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

Registrant Subsidiaries use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence.

The flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Excise Taxes

Registrant subsidiaries, as agents for some state and local governments collect from customers certain excise taxes levied by those state or local governments on our customers. We do not record these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their ratemaking treatment unless the debt is refinanced. If the reacquired debt, associated with the regulated business, is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Nonoperating Income or Nonoperating Expenses.

Debt discount or premium and debt issuance expenses are deferred and amortized utilizing the effective interest rate method over the term of the related debt. The amortization expense is included in interest charges.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings consistent with the timing of its inclusion in rates in accordance with SFAS 71.

Goodwill and Intangible Assets

In the first quarter of fiscal 2002, AEP's registrant subsidiaries adopted SFAS No. 142, "Goodwill and Other Intangible Assets" which revises the accounting for purchased goodwill and other intangible assets. Under SFAS No. 142, purchased goodwill and intangible assets with indefinite lives are no longer amortized, but instead tested for impairment at least annually. Intangible assets with finite lives, requires that they be amortized over their respective estimated lives to the estimated residual values. The AEP registrant subsidiaries have no recorded goodwill and intangible assets with indefinite lives as of December 31, 2003 and 2002. SWEPCo is the only AEP registrant with an intangible asset with a finite life on its books. See Note 3 for further information about SWEPCo's intangible asset.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed us to collect through rates to fund future decommissioning and spent fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) and the FERC have established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above)
- Maximum percentage invested in a specific type of investment
- Prohibition of investment in obligations of the applicable company or its affiliates

Trust funds are maintained for each regulatory jurisdiction and managed by investment managers external to AEP subsidiaries, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after-tax earnings of the trust, giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds for amounts relating to the Cook Plant and are included in Assets Held for Sale for amounts relating to the Texas Plants. See "Assets Held for Sale" section of Note 10 for further information regarding the Texas Plants. These securities are recorded at market value. Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Unrealized gains and losses from securities in these trust funds are reported as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

There were no material differences between net income and comprehensive income for AEGCo.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheet in the equity section. Accumulated Other Comprehensive Income (Loss) for AEP registrant subsidiaries as of December 31, 2003 and 2002 is shown in the following table.

Components	December 31, 2003	December 31, 2002
	(in thousands)	
Cash Flow Hedges:		
APCo	$(1,569)	$(1,920)
CSPCo	202	(267)
I&M	222	(286)
KPCo	420	322
OPCo	(103)	(738)
PSO	156	(42)
SWEPCo	184	(48)
TCC	(1,828)	(36)
TNC	(601)	(15)
Minimum Pension Liability:		
APCo	$(50,519)	$(70,162)
CSPCo	(46,529)	(59,090)
I&M	(25,328)	(40,201)
KPCo	(6,633)	(9,773)
OPCo	(48,704)	(72,148)
PSO	(43,998)	(54,431)
SWEPCo	(44,094)	(53,635)
TCC	(60,044)	(73,124)
TNC	(26,117)	(30,748)

Earnings Per Share (EPS)

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC are wholly-owned subsidiaries of AEP and are not required to report EPS.

Supplementary Information

The amounts of power purchased by the registrant subsidiaries from Ohio Valley Electric Corporation, which is 44.2% owned by the AEP System, for the years ended December 31, 2003, 2002 and 2001 were:

	APCo	CSPCo	I&M	OPCo
	(in thousands)			
Year Ended December 31, 2003	$55,219	$15,259	$25,659	$50,995
Year Ended December 31, 2002	53,386	14,885	23,282	50,135
Year Ended December 31, 2001	45,542	12,626	20,723	47,757

Reclassification

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income (Loss).

2. <u>NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES</u>

NEW ACCOUNTING PRONOUNCEMENTS

SFAS 132 (revised 2003) "Employers' Disclosure about Pensions and Other Postretirement Benefits"

In December 2003 the FASB issued SFAS 132 (revised 2003), which requires additional footnote disclosures about pensions and postretirement benefits, some of which are effective beginning with the year-end 2003 financial statements. Other additional disclosures will begin with APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC's 2004 quarterly financial statements.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC will implement new quarterly disclosures when they become effective in the first quarter of 2004, including (a) the amount of net periodic benefit cost for each period for which an income statement is presented, showing separately each component thereof, and (b) the amount of employer contributions paid and expected to be paid during the current year, if significantly different from amounts disclosed at the most recent year-end. See Note 11 for these additional 2003 disclosures.

SFAS 142 "Goodwill and Other Intangible Assets"

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, and that goodwill and intangible assets be tested annually for impairment. See Note 3 for further information on goodwill and other intangible assets.

SFAS 143 "Accounting for Asset Retirement Obligations"

We implemented SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003, which requires entities to record a liability at fair value for any legal obligations for asset retirements in the period incurred. Upon establishment of a legal liability, SFAS 143 requires a corresponding asset to be established which will be depreciated over its useful life. SFAS 143 requires that a cumulative effect of change in accounting principle be recognized for the cumulative accretion and accumulated depreciation that would have been recognized had SFAS 143 been applied to existing legal obligations for asset retirements. In addition, the cumulative effect of change in accounting principle is favorably affected by the reversal of accumulated removal cost. These costs had previously been recorded for generation and did not qualify as a legal obligation although these costs were collected in depreciation rates by certain formerly regulated subsidiaries.

We completed a review of our asset retirement obligations and concluded that we have related legal liabilities for nuclear decommissioning costs for I&M's Cook Plant and TCC's partial ownership in the South Texas Project, as well as liabilities for the retirement of certain ash ponds. Since we presently recover our nuclear decommissioning costs in our regulated cash flow and have existing balances recorded for such nuclear retirement obligations, we recognized the cumulative difference between the amount already provided through rates and the amount as measured by applying SFAS 143, as a regulatory asset or liability. Similarly, a regulatory asset was recorded for the cumulative effect of certain retirement costs for ash ponds related to our regulated operations. In 2003, we recorded an unfavorable cumulative effect for the non-regulated operations. See the table later in this section for a summary by registrant subsidiary of the cumulative effect of changes in accounting principles for the year ended December 31, 2003.

Certain of AEP's registrant subsidiaries have collected removal costs from ratepayers for certain assets that do not have associated legal asset retirement obligations. To the extent that such registrant subsidiaries have now been deregulated, the registrant subsidiaries reversed the balance of such removal costs which resulted in a net favorable cumulative effect in 2003. The following is a summary by registrant subsidiary of the removal costs reclassified from Accumulated Depreciation and Amortization to Asset Removal Costs in 2003 and to Deferred Credits and Other in 2002 (Other on AEGCo's 2002 Balance Sheet):

	December 31, 2003	December 31, 2002
	(in millions)	
AEGCo	$ 27.8	$ 28.0
APCo	92.5	94.6
CSPCo	99.1	96.0
I&M	263.0	250.5
KPCo	26.1	23.7
OPCo	101.2	97.0
PSO	214.0	202.6
SWEPCo	236.4	219.5
TCC (a)	104.8	97.5
TNC	76.7	75.0

(a) Includes $9 million classified as Liabilities Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets as of December 31, 2003 and 2002.

The following is a summary by registrant subsidiary of the cumulative effect of change in accounting principle, as a result of SFAS 143, for the year ended December 31, 2003:

	Pre-tax Income (Loss)		After-tax Income (Loss)	
	(in millions)			
	Ash Ponds	Reversal of Cost of Removal	Ash Ponds	Reversal of Cost of Removal
AEGCo	$ -	$ -	$ -	$ -
APCo	(18.2)	146.5	(11.4)	91.7
CSPCo	(7.8)	56.8	(4.7)	33.9
I&M	-	-	-	-
KPCo	-	-	-	-
OPCo	(36.8)	250.4	(21.9)	149.3
PSO	-	-	-	-
SWEPCo	-	13.0	-	8.4
TCC	-	-	-	-
TNC	-	4.7	-	3.1

We have identified, but not recognized, asset retirement obligation liabilities related to electric transmission and distribution as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements.

The following is a reconciliation of beginning and ending aggregate carrying amounts of asset retirement obligations by registrant subsidiary following the adoption of SFAS 143:

	Balance At January 1, 2003	Accretion	Liabilities Incurred	Balance at December 31, 2003
		(in millions)		
AEGCo (a)	$1.1	$-	$-	$1.1
APCo (a)	20.1	1.6	-	21.7
CSPCo (a)	8.1	0.6	-	8.7
I&M (b)	516.1	37.1	-	553.2
OPCo (a)	39.5	3.2	-	42.7
SWEPCo (d)	-	0.3	8.1	8.4
TCC (c)	203.2	15.6	-	218.8

(a) Consists of asset retirement obligations related to ash ponds.
(b) Consists of asset retirement obligations related to ash ponds ($1.1 million at December 31, 2003) and nuclear decommissioning costs for the Cook Plant ($552.1 million at December 31, 2003).
(c) Consists of asset retirement obligations related to nuclear decommissioning costs for STP included in Liabilities Held for Sale – Texas Generation Plants on TCC's Consolidated Balance Sheets.
(d) Consists of asset retirement obligations related to Sabine Mining which is now being consolidated under FIN 46 (see FIN 46 "Consolidation of Variable Interest Entities" later in this note).

Accretion expense is included in Other Operation expense in the respective income statements of the individual subsidiary registrants.

As of December 31, 2003 and 2002, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $845 million ($720 million for I&M and $125 million for TCC) and $716 million ($618 million for I&M and $98 million for TCC), respectively, recorded in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&M's Consolidated Balance Sheets and in Assets Held for Sale-Texas Generation Plants on TCC's Consolidated Balance Sheets.

Pro forma net income has not been presented for the years ended December 31, 2002 and 2001 because the pro forma application of SFAS 143 would result in pro forma net income not materially different from the actual amounts reported for those periods.

The following is a summary by registrant subsidiary of the pro forma liability for asset retirement obligations which has been calculated as if SFAS 143 had been adopted as of the beginning of each period presented:

	December 31,		
	2002	2001	2000
		(in millions)	
AEGCo	$ 1.1	$ 1.0	$0.9
APCo	20.1	18.7	17.3
CSPCo	8.1	7.5	6.9
I&M	516.1	481.4	449.1
KPCo	-	-	-
OPCo	39.5	36.5	33.8
PSO	-	-	-
SWEPCo	-	-	-
TCC	203.2	188.8	175.4
TNC	-	-	-

SFAS 144 "Accounting for the Impairment or Disposal of Long-lived Assets"

In August 2001, the FASB issued SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets" which sets forth the accounting to recognize and measure an impairment loss. This standard replaced, SFAS 121, "Accounting for Long-lived Assets and for Long-lived Assets to be Disposed Of." All of the registrant subsidiaries adopted SFAS 144 effective January 1, 2002. See Note 10 for discussion of impairments recognized in 2003 and 2002.

SFAS 145 "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections"

In April 2002, the FASB issued SFAS 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS 145). SFAS 145 rescinds SFAS 4, "Reporting Gains and Losses from Extinguishment of Debt," effective for fiscal years beginning after May 15, 2002. SFAS 4 required gains and losses from extinguishment of debt to be aggregated and classified as an extraordinary item if material. In 2003, TCC reclassified Extraordinary Losses (Net of Tax) on its reacquired debt of $2 million for 2001 to Nonoperating Expenses and Nonoperating Income Tax Expense.

SFAS 146 "Accounting for Costs Associated with Exit or Disposal Activities"

In June 2002, FASB issued SFAS 146 which addresses accounting for costs associated with exit or disposal activities. This statement supersedes previous accounting guidance, principally EITF No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. SFAS 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that the liability should initially be measured and recorded at fair value. The time at which we recognize future costs related to exit or disposal activities, including restructuring, as well as the amounts recognized may be affected by SFAS 146. The registrant subsidiaries adopted the provisions of SFAS 146 for exit or disposal activities initiated after December 31, 2002.

SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

On April 30, 2003, the FASB issued Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends SFAS 133 to clarify the definition of a derivative and the requirements for contracts to qualify as "normal purchase/normal sale." SFAS 149 also amends certain other existing pronouncements. Effective July 1, 2003, registrant subsidiaries implemented SFAS 149 and the effect was not material to our results of operations, cash flows or financial condition.

SFAS 150 "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"

We implemented SFAS 150 effective July 1, 2003. SFAS 150 is the first phase of the FASB's project to eliminate from the balance sheet the "mezzanine" presentation of items with characteristics of both liabilities and equity, including: (1) mandatorily redeemable shares, (2) instruments other than shares that could require the issuer to buy back some of its shares in exchange for cash or other assets and (3) certain obligations that can be settled with shares. Measurement of these liabilities generally is to be at fair value, with the payment or accrual of "dividends" and other amounts to holders reported as interest cost.

Beginning with our third quarter 2003 financial statements, we present Cumulative Preferred Stocks Subject to Mandatory Redemption as Liability for Cumulative Preferred Stock Subject to Mandatory Redemption. Beginning July 1, 2003, we classify dividends on these mandatorily redeemable preferred shares as Interest Charges. In accordance with SFAS 150, dividends from prior periods remain classified as Preferred Stock Dividends.

FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"

In November 2002, the FASB issued FIN 45 which clarifies the accounting to recognize a liability related to issuing a guarantee, as well as additional disclosures of guarantees. We implemented FIN 45 as of January 1, 2003, and the effect was not material to our results of operations, cash flows or financial condition. See Note 8 for further disclosures.

FIN 46 (revised December 2003) "Consolidation of Variable Interest Entities" and FIN 46 "Consolidation of Variable Interest Entities"

We implemented FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. FIN 46 interprets the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Due to the prospective application of FIN 46, we did not reclassify prior period amounts.

On July 1, 2003, we deconsolidated the trusts which hold mandatorily redeemable trust preferred securities. Therefore, of the $321 million net amount ($75 million PSO, $110 million SWEPCo and $136 million TCC), reported as "Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries" at December 31, 2002, $331 million ($77 million PSO, $113 million SWEPCo and $141 million TCC) is reported as a component of Long-term Debt and $10 million ($2 million PSO, $3 million SWEPCo and $5 million TCC) is reported in Other Investments within Other Property and Investments at December 31, 2003.

Effective July 1, 2003, SWEPCo consolidated Sabine Mining Company (Sabine), a contract mining operation providing mining services to SWEPCo. Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of our requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Effective July 1, 2003, OPCo consolidated JMG. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There is no cumulative effect of an accounting change recorded as a result of our requirement to consolidate JMG, and there is no change in net income due to the consolidation of JMG. See Note 15 "Leases" for further disclosures.

In December 2003, the FASB issued FIN 46 (revised December 2003) (FIN 46R) which replaces FIN 46. The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

EITF 02-3 and the Rescission of EITF 98-10

In October 2002, the Emerging Issues Task Force of the FASB reached a final consensus on Issue No. 02-3. EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Under EITF 02-3, mark-to-market accounting is precluded for risk management contracts that are not derivatives pursuant to SFAS 133. The consensus to rescind EITF 98-10 also eliminated the recognition of physical inventories at fair value other than as provided by GAAP. Registrant subsidiaries have implemented this standard for all physical inventory and non-derivative risk management transactions occurring on or after October 25, 2002. For physical inventory and non-derivative risk management transactions entered into prior to October 25, 2002, registrant subsidiaries implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change (see "Cumulative Effect of Accounting Change" for a summary by registrant subsidiary).

Effective January 1, 2003, EITF 02-3 requires that gains and losses on all derivatives, whether settled financially or physically, be reported in the income statement on a net basis if the derivatives are held for risk management purposes. Previous guidance in EITF 98-10 permitted contracts that were not settled financially to be reported either gross or net in the income statement. Prior to the third quarter of 2002, the registrant subsidiaries recorded and reported upon settlement, sales under forward risk management contracts as revenues. Registrant subsidiaries also recorded and reported purchases under forward risk management contracts as purchased energy expenses. Effective July 1, 2002, the registrant subsidiaries reclassified such forward risk management revenues and purchases on a net basis. The reclassification of such risk management activities to a net basis of reporting resulted in a substantial reduction in both revenues and purchased energy expense, but did not have any impact on financial condition, results of operations or cash flows.

EITF 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3"

In July 2003, the EITF reached consensus on Issue No. 03-11. The consensus states that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. The adoption of EITF 03-11 did not have a material impact on our results of operations, financial position or cash flows.

FASB Staff Position No. 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

On January 12, 2004, the FASB Staff issued FSP 106-1, which allows a one-time election to defer accounting for any effects of the prescription drug subsidy under the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act), enacted on December 8, 2003. There are significant uncertainties as to whether AEP's plan will be eligible for a subsidy under future federal regulations that have not yet been drafted. The method of accounting for any such subsidy and, therefore, the subsidy's possible reduction to the accumulated postretirement benefit obligation and periodic postretirement benefit costs has not been resolved by the FASB or other professional accounting standard setting authority. Accordingly, any potential effects of the Act were deferred until authoritative guidance on the accounting for the federal subsidy is issued. Measurements of the accumulated postretirement benefit obligation and periodic postretirement benefit cost included in these financial statements do not reflect any potential effects of the Act. APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC cannot determine what impact, if any, new authoritative guidance on the accounting for the federal subsidy may have on our results of operations or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing. Until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Certain registrant subsidiaries have recorded after tax charges against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in Cumulative Effect of Accounting Changes in the first quarter of 2003. This amount will be realized when the positions settle.

The FASB's Derivative Implementation Group (DIG) issued accounting guidance under SFAS 133 for certain derivative fuel supply contracts with volumetric optionality and derivative electricity capacity contracts. This guidance, effective in the third quarter of 2001, concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when certain option-type contracts and forward contracts in electricity can qualify for the normal purchase or sale exclusion.

Asset Retirement Obligations (SFAS 143)

In the first quarter of 2003, certain of the registrant subsidiaries recorded in after-tax income a cumulative effect of accounting change for Asset Retirement Obligations.

The following is a summary by registrant subsidiary of the cumulative effect of changes in accounting principles recorded in 2003 for the adoptions of SFAS 143 and EITF 02-3 (no effect on AEGCo or PSO):

	SFAS 143 Cumulative Effect		EITF 02-3 Cumulative Effect	
	Pre-tax Income (Loss)	After-tax Income (Loss)	Pre-tax Income (Loss)	After-tax Income (Loss)
	(in millions)		(in millions)	
APCo	$128.3	$ 80.3	$ (4.7)	$ (3.0)
CSPCo	49.0	29.3	(3.1)	(2.0)
I&M	-	-	(4.9)	(3.2)
KPCo	-	-	(1.7)	(1.1)
OPCo	213.6	127.3	(4.2)	(2.7)
SWEPCo	13.0	8.4	0.2	0.1
TCC	-	-	0.2	0.1
TNC	4.7	3.1	-	-

EXTRAORDINARY ITEMS

In 2003 an extraordinary item of $177,000, net of tax of $95,000, was recorded at TNC for the discontinuance of regulatory accounting under SFAS 71 in compliance with a FERC Order dated December 24, 2003 approving a Settlement. AEP's registrant subsidiaries had no extraordinary items in 2002. In 2001 an extraordinary item was recorded for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of the business in the Ohio state jurisdiction. OPCo and CSPCo recognized an extraordinary loss of $48 million (net of tax of $20 million) for unrecoverable Ohio Public Utility Excise Tax (commonly known as the Gross Receipts Tax – GRT) net of allowable Ohio coal credits. This loss resulted from regulatory decisions in connection with Ohio deregulation which stranded the recovery of the GRT. Effective with the liability affixing on May 1, 2001, CSPCo and OPCo recorded an extraordinary loss under SFAS 101. Both Ohio companies appealed to the Ohio Supreme Court the PUCO order on Ohio restructuring that the Ohio companies believe failed to provide for recovery for the final year of the GRT. In April 2002, the Ohio Supreme Court denied recovery of the final year of the GRT.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

There is no goodwill carried by any of the AEP registrant subsidiaries.

Acquired Intangible Assets

SWEPCo's acquired intangible asset subject to amortization is $21.7 million at December 31, 2003 and $24.7 million at December 31, 2002, net of accumulated amortization. The gross carrying amount, accumulated amortization and amortization life are:

		December 31, 2003		December 31, 2002	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Advanced royalties	10	$29.4	$7.7	$29.4	$4.7

Amortization of the intangible asset was $3.0 million for the twelve months ended December 31, 2003 and 2002. SWEPCo's estimated aggregate amortization expense is $3 million for each year 2004 through 2010 and $1 million in 2011.

4. RATE MATTERS

In certain jurisdictions, we have agreed to base rate or fuel recovery limitations usually under terms of settlement agreements. See Note 5 for a discussion of those terms related to Nuclear Plant Restart and Merger with CSW.

Fuel in SPP Area of Texas – Affecting SWEPCo and TNC

In 2001, the PUCT delayed the start of customer choice in the SPP area of Texas. In May 2003, the PUCT ordered that competition would not begin in the SPP areas before January 1, 2007. TNC filed with the PUCT in 2002 to determine the most appropriate method to reconcile fuel costs in TNC's SPP area. In April 2003, the PUCT issued an order adopting the methodology proposed in TNC's filing, with adjustments, for reconciling fuel costs in the SPP area. The adjustments removed $3.71 per MWH from reconcilable fuel expense. This adjustment will reduce revenues received by Mutual Energy SWEPCo who now serves TNC's SPP customers by approximately $400,000 annually. In October 2003, Mutual Energy SWEPCo agreed with the PUCT staff and the Office of Public Utility Counsel (OPC) to file a fuel reconciliation proceeding for the period January 2002 through December 2003 by March 31, 2004 and the PUCT ordered that the filing be made.

TNC Fuel Reconciliation – Affecting TNC

In June 2002, TNC filed with the PUCT to reconcile fuel costs, requesting to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory. At December 31, 2001, the deferred under-recovery balance associated with TNC's ERCOT service area was $27.5 million including interest. During the reconciliation period, TNC incurred $293.7 million of eligible fuel costs serving both ERCOT and SPP retail customers. TNC also requested authority to surcharge its SPP customers for under-recovered fuel costs. TNC's SPP customers will continue to be subject to fuel reconciliations until competition begins in the SPP area as described above. The under-recovery balance at December 31, 2001 for TNC's service within SPP was $0.7 million including interest.

In March 2003, the ALJ in this proceeding filed a Proposal for Decision (PFD) with a recommendation that TNC's under-recovered retail fuel balance be reduced. In March 2003, TNC established a reserve of $13 million based on the recommendations in the PFD. In May 2003, the PUCT reversed the ALJ on certain matters and remanded TNC's final fuel reconciliation to the ALJ to consider two issues. The issues are the sharing of off-system sales margins from AEP's trading activities with customers for five years per the PUCT's interpretation of the Texas AEP/CSW merger settlement and the inclusion of January 2002 fuel factor revenues and associated costs in the determination of the under-recovery. The PUCT proposed that the sharing of off-system sales margins for periods beyond the termination of the fuel factor should be recognized in the final fuel reconciliation proceeding. This would result in the sharing of margins for an additional three and one half years after the end of the Texas ERCOT fuel factor.

On December 3, 2003, the ALJ issued a PFD in the remand phase of the TNC fuel reconciliation recommending additional disallowances for the two remand issues. TNC filed responses to the PFD and the PUCT announced a final ruling in the fuel reconciliation proceeding on January 15, 2004 accepting the PFD. TNC is waiting for a written order, after which it will request a rehearing of the PUCT's ruling. While management believes that the Texas merger settlement only provided for sharing of margins during the period fuel and generation costs were regulated by the PUCT, an additional provision of $10 million was recorded in December 2003. Based on the decisions of the PUCT, TNC's final under-recovery including interest at December 31, 2003 was $6.2 million.

In February 2002, TNC received a final order from the PUCT in a previous fuel reconciliation covering the period July 1997 to June 2000 and reflected the order in its financial statements. This final order was appealed to the Travis County District Court. In May 2003, the District Court upheld the PUCT's final order. That order is currently on appeal to the Third Court of Appeals.

TCC Fuel Reconciliation - Affecting TCC

In December 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the 2004 true-up proceeding. This reconciliation covers the period of July 1998 through December 2001. At December 31, 2001, the over-recovery balance for TCC was $63.5 million including interest. During the reconciliation period, TCC incurred $1.6 billion of eligible fuel and fuel-related expenses.

Based on the PUCT ruling in the TNC proceeding relating to similar issues, TCC established a reserve for potential adverse rulings of $81 million during 2003. In July 2003, the ALJ requested that additional information be provided in the TCC fuel reconciliation related to the impact of the TNC orders, referenced above, on TCC. On February 3, 2004, the ALJ issued a PFD recommending that the PUCT disallow $140 million in eligible fuel costs including some new items not considered in the TNC case, and other items considered but not disallowed in the TNC ruling. At this time, management is unable to predict the outcome of this proceeding. An adverse ruling from the PUCT, disallowing amounts in excess of the established reserve could have a material impact on future results of operations, cash flows and financial condition. Additional information regarding the 2004 true-up proceeding for TCC can be found in Note 6 "Customer Choice and Industry Restructuring."

SWEPCo Texas Fuel Reconciliation – Affecting SWEPCo

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in SPP. This reconciliation covers the period of

January 2000 through December 2002. At December 31, 2002, SWEPCo's filing included a $2 million deferred over-recovery balance including interest. During the reconciliation period, SWEPCo incurred $435 million of Texas retail eligible fuel expense. In November 2003, intervenors and the PUCT Staff recommended fuel cost disallowances of more than $30 million. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation. The settlement provides for a disallowance in fuel costs of $8 million which was recorded in December 2003. In addition, the settlement provides for the deferral as a regulatory asset of costs of a new lignite mining agreement in excess of a specified benchmark for lignite at SWEPCo's Dolet Hills Plant. The settlement provides for recovery of those deferred costs over a period ending in April 2011 as cost savings are realized under the new mining agreement. The settlement also will allow future recovery of litigation costs associated with the termination of a previous lignite mining agreement if future costs savings are adequate. The settlement will be filed with the PUCT for approval.

ERCOT Price-to-Beat Fuel Factor Appeal – Affecting TCC and TNC

Several parties including the OPC and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. On June 25, 2003, the District Court ruled in both appeals. The Court ruled in the Mutual Energy WTU case that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, and that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The Court upheld the initial PTB orders on all other issues. In the Mutual Energy CPL proceeding, the Court ruled that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately $2.7 million for Mutual Energy WTU. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. The District Court decision was appealed to the Third Court of Appeals by Mutual Energy CPL, Mutual Energy WTU and other parties. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the District Court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in 2002 and 2003 resulting in an adverse effect on future results of operations and cash flows.

Unbundled Cost of Service (UCOS) Appeal – Affecting TCC

The UCOS proceeding established the regulated wires rates to be effective when retail electric competition began. TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. Regulated delivery charges include the retail transmission and distribution charge and, among other items, a nuclear decommissioning fund charge, a municipal franchise fee, a system benefit fund fee, a transition charge associated with securitization of regulatory assets and a credit for excess earnings. Certain rulings of the PUCT in the UCOS proceeding, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, regulatory treatment of nuclear insurance and distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to non-bypassable transmission and distribution rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. The distribution rate credit began in January 2002. This decision could potentially affect the PTB rates charged by Mutual Energy CPL and could result in a refund to certain of its customers. Mutual Energy CPL was a subsidiary of AEP until December 23, 2002 when it was sold. Management estimates that the effect of a decision to reduce the PTB rates for the period prior to the sale is approximately $11 million pre-tax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

TCC Rate Case – Affecting TCC

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCC's proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%. On February 9, 2004, eight intervening parties filed testimony recommending reductions to TCC's requested $67 million rate increase. The recommendations range from a decrease in existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. The PUCT Staff filed testimony, on February 17, 2004, recommending reductions to TCC's request of approximately $51 million. TCC's rebuttal testimony was filed on February 26, 2004. Hearings are scheduled for March 2004 with a PUCT decision expected in May 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates or its impact on TCC's results of operations, cash flows and financial condition.

Louisiana Fuel Audit – Affecting SWEPCO

The LPSC is performing an audit of SWEPCo's historical fuel costs. In addition, five SWEPCo customers filed a suit in the Caddo Parish District Court in January 2003 and filed a complaint with the LPSC. The customers claim that SWEPCo has over charged them for fuel costs since 1975. The LPSC consolidated the customer complaint and audit. In January 2004, a procedural schedule was issued requiring LPSC Staff and intervenor testimony to be filed in June 2004 and scheduling hearings for October 2004. Management believes that SWEPCo's fuel costs were proper and those costs incurred prior to 1999 have been approved by the LPSC. Management is unable to predict the outcome of these proceedings. If the actions of the LPSC or the Court result in a material disallowance of recovery of SWEPCo's fuel costs from customers, it could have an adverse impact on results of operations and cash flows.

Louisiana Compliance Filing – Affecting SWEPCo

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of their order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid 2005. The filing indicates that SWEPCo's current rates should not be reduced. In 2004 the LPSC required SWEPCo to file updated financial information with a test year ending December 31, 2003 before April 16, 2004. If, after review of the updated information, the LPSC disagrees with our conclusion, they could order SWEPCo to file all documents for a full cost of service revenue requirement review in order to determine whether SWEPCo's capped rates should be reduced which would adversely impact results of operations and cash flows.

FERC Wholesale Fuel Complaints – Affecting TNC

Certain TNC wholesale customers filed a complaint with FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs since 1997.

Negotiations to settle the complaint and update the contracts resulted in new contracts. The FERC approved an offer of settlement regarding the fuel complaint and new contracts at market prices in December 2003. Since TNC had recorded a provision for refund in 2002, the effect of the settlement was a $4 million favorable adjustment recorded in December 2003. See Note 2 for a discussion of TNC's discontinuance of SFAS 71 accounting for its FERC jurisdictional customers.

Environmental Surcharge Filing – Affecting KPCo

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately $21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant. See NOx Reductions in Note 7.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million became effective in May 2003 and an additional $16.2 million became effective in July 2003. The recovery of such amounts is intended to offset KPCo's cost of compliance with the Clean Air Act.

PSO Rate Review – Affecting PSO

In February 2003, the Director of the OCC filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003, PSO filed financial information and supporting testimony in response to the OCC's requirements. PSO's response indicates that its annual revenues are $36 million less than costs. As a result, PSO is seeking OCC approval to increase its base rates by that amount, which is a 3.6% increase over PSO's existing revenues. Hearings are scheduled for October 2004. Management is unable to predict the ultimate effect of this review on PSO's rates or its impact on PSO's results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power – Affecting PSO

PSO had a $44 million under-recovery of fuel costs resulting from a 2002 reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the OCC seeking recovery of the $44 million over an 18-month time period. In August 2003, the OCC Staff filed testimony recommending PSO be granted recovery of $42.4 million over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed its testimony in February 2004 and hearings will occur in June 2004. If the OCC determines as a result of the review that a portion of PSO's fuel and purchased power costs should not be recovered, there will be an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

Merger Mitigation Sales – Affecting PSO, SWEPCo, TCC and TNC

As a condition of AEP/CSW merger approval at the FERC, the AEP West companies were required to mitigate market power concerns in SPP by divesting 300 MW of SPP capacity and selling 300 MW of SPP capacity at auction on an interim basis until the divestiture is completed. The margins from the interim sales were to be shared with customers in accordance with the existing margin sharing if they were positive on an annual basis and customers were to be held harmless if the margins on an annual basis were negative. Consequently, for proper accounting, the margins were deferred until year-end.

On September 1, 2003, AEP sold its share of the Eastex plant located in SPP. As a result of the sale, AEP satisfied the 300 MW FERC divestiture requirement in SPP. Based on the advice of counsel, management has concluded that it is no longer required to make the agreed upon 300 MW interim merger mitigation sale. The AEP West companies had $8.7 million of net merger mitigation sales losses deferred. Since these sales are no longer required, the final adjustment to the accrual occurred in September 2003. The amounts of revenues reversed were $8.6 million by PSO, $0.7 million by TCC and $1.2 million by TNC. SWEPCo recorded its gain of $1.8 million as revenues.

Virginia Fuel Factor Filing – Affecting APCo

APCo filed with the Virginia SCC to reduce its fuel factor effective August 1, 2003. The requested fuel rate reduction was approved by the Virginia SCC and is effective for 17 months (August 1, 2003 to December 31, 2004) and is estimated to reduce revenues by $36 million during that period. This fuel factor adjustment will reduce cash flows without impacting results of operations as any over-recovery or under-recovery of fuel costs would be deferred as a regulatory liability or a regulatory asset.

FERC Long-term Contracts – Affecting AEP East and AEP West companies

In 2002, the FERC set for hearing complaints filed by certain wholesale customers located in Nevada and Washington that sought to break long-term contracts which the customers alleged were "high-priced." At issue were long-term contracts entered into during the California energy price spike in 2000 and 2001. The complaints alleged that AEP sold power at unjust and unreasonable prices.

In February 2003, AEP and one of the customers agreed to terminate their contract. The customer withdrew its FERC complaint and paid \$59 million to AEP. As a result of the contract termination, AEP reversed \$69 million of unrealized mark-to-market gains previously recorded, resulting in a \$10 million pre-tax loss.

In December 2002, a FERC ALJ ruled in favor of AEP and dismissed a complaint filed by two Nevada utilities. In 2000 and 2001, we agreed to sell power to the utilities for future delivery. In 2001, the utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities had failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The utilities requested a rehearing which the FERC denied. The utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

RTO Formation/Integration Costs – Affecting APCo, CSPCo, I&M, KPCo, and OPCo

With FERC approval, AEP East companies have been deferring costs incurred under FERC orders to form an RTO (the Alliance RTO) or join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both our Alliance formation costs and our PJM integration costs including the deferral of a carrying charge. The AEP East companies have deferred approximately \$28 million of RTO formation and integration costs and related carrying charges through December 31, 2003. Amounts per company are as follows:

Company	**(in millions)**
APCo	\$7.8
CSPCo	3.3
I&M	6.0
KPCo	1.8
OPCo	8.6

As a result of the subsequent delay in the integration of AEP's East transmission system into PJM, FERC declined to rule, in its July 2003 order, on our request to transfer the deferrals to regulatory assets, and to maintain the deferrals until such time as the costs can be recovered from all users of AEP's East transmission system. The AEP East companies will apply for permission to transfer the deferred formation/integration costs to a regulatory asset prior to integration with PJM. In August 2003, the Virginia SCC filed a request for rehearing of the July 2003 order, arguing that FERC's action was an infringement on state jurisdiction, and that FERC should not have treated Alliance RTO startup costs in the same manner as PJM integration costs. On October 22, 2003, FERC denied the rehearing request.

In its July 2003 order, FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the open access transmission tariff (OATT) to be charged by PJM. Management believes that the FERC will grant permission for the deferred RTO costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of AEP East companies' portion of the OATT at the time they join PJM. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo. APCo's Virginia retail base rates are capped with an opportunity for a one-time increase in non-generation rates after January 1, 2004. We intend to file an application with FERC seeking permission to delay the amortization of the deferred RTO formation/integration costs until they are recoverable from all users of the transmission system including retail customers. Management is unable to predict the timing of when AEP will join PJM and if upon joining PJM whether FERC will grant a delay of recovery until the rate caps and freezes end. If the AEP East companies do not obtain regulatory approval to join PJM, we are committed to reimburse PJM for certain project implementation costs (presently estimated at $24 million for the entire PJM integration project). If incurred, PJM project implementation costs will be allocated among the AEP East companies. Management intends to seek recovery of the deferred RTO formation/integration costs and project implementation cost reimbursements, if incurred. If the FERC ultimately decides not to approve a delay or the state commissions deny recovery, future results of operations and cash flows could be adversely affected.

In the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed with the Virginia SCC a cost/benefit study covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In August 2003, KPCo sought and was granted a rehearing to submit additional evidence. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately $13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. The order was based on PURPA 205(a), which allows FERC to exempt electric utilities from state law or regulation in certain circumstances. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the exceptions under PURPA apply. The FERC directed the ALJ to issue an initial decision by March 15, 2004.

FERC Order on Regional Through and Out Rates – Affecting APCo, CSPCo, I&M, KPCo and OPCo

In July 2003, the FERC issued an order directing PJM and the Midwest ISO to make compliance filings for their respective Open Access Transmission Tariffs to eliminate, by November 1, 2003, the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (RTO Footprint). In October 2003, the FERC postponed the November 1, 2003 deadline to eliminate T&O rates. The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs' revenue distribution protocols. The order provided that affected transmission owners could file to offset the elimination of these revenues by increasing rates or utilizing a transitional rate mechanism to recover lost revenues that result from the elimination of the T&O rates. The FERC also found that the T&O rates of some of the former Alliance RTO companies, including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the RTO Footprint. FERC initiated an investigation and hearing in regard to these rates. We made a filing with the FERC to support the justness and reasonableness of our rates. We also made a joint filing with unaffiliated utilities proposing a regional revenue replacement mechanism for the lost revenues, in the event that FERC eliminated all T&O rates for delivery points within the RTO Footprint. In orders issued in November 2003, the FERC dismissed the joint filing, but adopted a new regional rate design substantially in the form proposed in the joint filing. The orders, directed each transmission provider to file compliance rates to eliminate T&O rates prospectively within the region and simultaneously implement a new seams elimination cost allocation (SECA) rates to mitigate the lost revenues for a two-year transition period beginning April 1, 2004. The FERC did not indicate the recovery method for the revenues after the two-year period. As required by the FERC, we filed compliance tariff changes in January 2004 to eliminate the T&O charges within the RTO Footprint. The SECA rate issues that remain unresolved have been set before an ALJ for settlement procedures, and the effective date of the T&O rate elimination and SECA rates were delayed until May 1, 2004. The November 2003 orders have been appealed by a number of parties. The AEP East companies received approximately $150 million of T&O rate revenues from transactions delivering energy to customers in the RTO Footprint for the twelve months ended June 30, 2003. At this time, management is unable to predict whether the new SECA rates will fully compensate the AEP East companies for their lost T&O rate revenues and, consequently, their impact on our future results of operations, cash flows and financial condition.

Indiana Fuel Order – Affecting I&M

On July 17, 2003, I&M filed a fuel adjustment clause application requesting authorization to implement the fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant Outage) for electric service for the billing months of October 2003 through February 2004, and for approval of a new fuel cost adjustment credit for electric service to be applicable during the March 2004 billing month.

On August 27, 2003, the IURC issued an order approving the requested fixed fuel adjustment charge for October 2003 through February 2004. The order further stated that certain parties must negotiate the appropriate action on fuel to commence on March 1, 2004. Such negotiations are ongoing. The IURC deferred ruling on the March 2004 factor until after January 1, 2004.

Michigan 2004 Fuel Recovery Plan – Affecting I&M

The MPSC's December 16, 1999 order approved a Settlement Agreement regarding the extended outage of the Cook Plant and fixed I&M Power Supply Cost Recovery (PSCR) factors for the St. Joseph and Three Rivers rate areas through December 2003. In accordance with the settlement, PSCR Plan cases were not required to be filed through the 2003 plan year. As required, I&M filed its 2004 PSCR Plan with the MPSC on September 30, 2003 seeking new fuel and power supply recovery factors to be effective in 2004. The case has been scheduled for hearing. As allowed by Michigan law, the proposed factors were effective on January 1, 2004, subject to review and possible adjustment based on the results of the hearing.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEGCo			APCo		
	2003	2002	Recovery/Refund Period	2003	2002	Recovery/Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$325,889	$209,884	Various Periods (a)
Transition Regulatory Assets – Virginia				30,855	39,670	Up to 4 Years (a)
Transition Regulatory Assets – West Virginia				-	119,038	N/A
Deferred Fuel Costs				-	5,367	N/A
Unamortized Loss on Reacquired Debt	$4,733	$4,970	22 Years (b)	19,005	9,147	Up to 29 Years (b)
Asset Retirement Obligations	928	-	Various Periods (a)	9,048	-	Various Periods (a)
Unrealized Loss on Forward Commitments				17,006	-	Various Periods (a)
Other				15,393	12,447	Various Periods (a)
Total Regulatory Assets	$5,661	$4,970		$417,196	$395,553	
Regulatory Liabilities:						
Asset Removal Costs	$27,822	$-	(d)	$92,497	$-	(d)
Deferred Investment Tax Credits	49,589	52,943	Up to 19 Years (a)	30,545	33,691	Up to 17 Years (c)
WV Rate Stabilization Deferral				-	75,601	N/A
SFAS 109 Regulatory Liability, Net	15,505	16,670	Various Periods (a)			
Over Recovery of Fuel Costs – West Virginia				55,250	-	(a)
Unrealized Gain on Forward Commitments				17,283	-	Various Periods (a)
Over Recovery of Fuel Costs – Virginia				13,454	-	1 Year (b)
Other				43	72	Various Periods (a)
Total Regulatory Liabilities	$92,916	$69,613		$209,072	$109,364	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) A portion of this amount effectively earns a return.
(d) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	CSPCo			I&M		
	2003	2002	Recovery/Refund Period	2003	2002	Recovery/Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$16,027	$26,290	Various Periods (a)	$151,973	$163,928	Various Periods (a)
Transition Regulatory Assets	188,532	204,961	Up to 5 Years (a)			
Deferred Fuel Costs				-	37,501	N/A
Unamortized Loss on Reacquired Debt	13,659	5,978	Up to 20 Years (b)	18,424	14,994	Up to 29 Years (b)
Cook Plant Restart Costs				-	40,000	N/A
Incremental Nuclear Refueling Outage Expenses, Net				57,326	29,572	(c)
DOE Decontamination and Decommissioning Assessment				18,863	23,375	Up to 5 Years (a)
Other	24,966	20,453	Various Periods (a)	29,691	38,842	Various Periods (a)
Total Regulatory Assets	$243,184	$257,682		$276,277	$348,212	
Regulatory Liabilities:						
Asset Removal Costs	$99,119	$-	(e)	$263,015	$-	(e)
Deferred Investment Tax Credits	30,797	33,907	Up to 17 Years (a)	90,278	97,709	Up to 19 Years (a)
Excess ARO for Nuclear Decommissioning				215,715	-	(d)
Unrealized Gain on Forward Commitments				25,010	36,804	Various Periods (a)
Other				36,258	29,179	Various Periods (a)
Total Regulatory Liabilities	$129,916	$33,907		$630,276	$163,692	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage and does not earn a return.
(d) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. Accrues monthly, will be paid when the nuclear plant is decommissioned and earns a return.
(e) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	KPCo 2003	KPCo 2002	KPCo Recovery/Refund Period	OPCo 2003	OPCo 2002	OPCo Recovery/Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$99,828	$87,261	Various Periods (a)	$169,605	$165,106	Various Periods (a)
Transition Regulatory Assets				310,035	375,409	4 years (a)
Unamortized Loss on Reacquired Debt	1,088	152	Up to 29 Years (b)	10,172	4,899	Up to 34 Years (b)
Other	12,883	14,563	Various Periods (a)	22,506	23,227	Various Periods (a)
Total Regulatory Assets	$113,799	$101,976		$512,318	$568,641	
Regulatory Liabilities:						
Asset Removal Costs	$26,140	$-	(c)	$101,160	$-	(c)
Deferred Investment Tax Credits	7,955	9,165	Up to 17 Years (a)	15,641	18,748	Up to 17 Years (a)
Unrealized Gain on Forward Commitments	9,174	10,967	Various Periods (a)			
Other	1,417	1,185	Various Periods (a)	3	1,237	Various Periods (a)
Total Regulatory Liabilities	$44,686	$21,317		$116,804	$19,985	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	PSO 2003	PSO 2002	PSO Recovery/Refund Period	SWEPCo 2003	SWEPCo 2002	SWEPCo Recovery/Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$3,235	$19,855	Various Periods (b)
Under-recovered Fuel Costs	$24,170	$76,470	1 Year (a)	11,394	2,865	1 Year (a)
Unamortized Loss on Reacquired Debt	14,357	11,138	Up to 12 Years (b)	19,331	17,031	Up to 40 Years (b)
Other	14,342	15,012	Various Periods (c)	15,859	12,347	Various Periods (c)
Total Regulatory Assets	$52,869	$102,620		$49,819	$52,098	
Regulatory Liabilities:						
Asset Removal Costs	$214,033	$-	(e)	$236,409	$-	(e)
Deferred Investment Tax Credits	30,411	32,201	Up to 26 Years (d)	39,864	44,190	Up to 14 Years (d)
SFAS 109 Regulatory Liability, Net	24,937	27,893	Various Periods (b)			
Over-Recovered Fuel Costs				4,178	17,226	1 Year (a)
Excess Earnings				2,600	3,700	(d)
Unrealized Gains on Forward Commitments	15,406	4,360	Various Periods (c)	11,793	1,992	Various Periods (c)
Other	-	31	Various Periods (c)	6,986	1,402	Various Periods (c)
Total Regulatory Liabilities	$284,787	$64,485		$301,830	$68,510	

(a) Deferred fuel for PSO's Oklahoma jurisdiction & SWEPCo's Arkansas and Louisiana jurisdictions does not earn a return. Texas jurisdictional amounts do earn a return.
(b) Amount effectively earns a return.
(c) Amounts are both earning and not earning a return.
(d) Amount does not earn a return.
(e) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	TCC			TNC		
	2003	2002	Recovery/Refund Period	2003	2002	Recovery/Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$3,249	$9,950	Various Periods (a)			
Designated For Securitization	1,253,289	330,960	(b)			
Deferred Fuel Costs				$26,680	$26,680	(c)
Wholesale Capacity Auction True-up	480,000	262,000	(c)			
Unamortized Loss on Reacquired Debt	9,086	8,661	Up to 34 Years (a)	3,929	3,283	Up to 17 Years (a)
Deferred Debt – Restructuring	12,015	13,324	Up to 14 Years (a)	6,579	10,134	Up to 14 Years (a)
DOE Decontamination and Decommissioning Assessment	3,268	3,170	1 Year (d)			
Other	130,645	166,931	Various Periods (e)	3,332	5,000	Various Periods (e)
Total Regulatory Assets	$1,891,552	$794,996		$40,520	$45,097	
Regulatory Liabilities:						
Asset Removal Costs	$95,415	$-	(f)	$76,740	$-	(f)
Deferred Investment Tax Credits	112,479	117,686	Up to 25 Years (d)	19,990	21,510	Up to 19 Years (d)
Deferred Fuel Costs	69,026	69,026	(c)			
Retail Clawback	45,527	51,926	(c)	11,804	14,328	(c)
Over – Recovery of Transition Charges	22,499	20,870	Up to 13 Years (a)			
Purchased Power Conservation	9,234	9,560	Various Periods (e)			
Excess Earnings	25,246	46,111	(b)	14,262	17,419	Up to 30 Years (a)
SFAS 109 Regulatory Liability, Net				13,655	12,280	Various Periods (a)
Other	5	6	Various Periods (e)	1,826	7,285	Various Periods (e)
Total Regulatory Liabilities	$379,431	$315,185		$138,277	$72,822	

(a) Amount earns a return.
(b) Will be included in TCC's PUCT 2004 true-up proceedings and is designated for possible securitization during 2005.
(c) Amount will be included in TCC's and TNC's 2004 true-up proceedings for future recovery/payment over a time period to be determined in a future PUCT proceeding.
(d) Amount does not earn a return.
(e) Amounts are both earning and not earning a return.
(f) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

Texas Restructuring Related Regulatory Assets and Liabilities

Regulatory assets Designated for Securitization, Wholesale Capacity Auction True-up regulatory assets, Deferred Fuel Costs and Retail Clawback regulatory liabilities are not being currently recovered from or returned to ratepayers. Management believes that the laws and regulations, established in Texas for industry restructuring, provide for the recovery from ratepayers of these net amounts. See Note 6 for a complete discussion of our plans to recover these regulatory assets, net of regulatory liabilities.

Nuclear Plant Restart

I&M completed the restart of both units of the Cook Plant in 2000. Settlement agreements in the Indiana and Michigan retail jurisdictions that addressed recovery of Cook Plant related outage costs were approved in 1999 by the IURC and MPSC.

The amount of deferrals amortized to other O&M expenses were $40 million in 2003, 2002 and 2001. Also pursuant to the settlement agreements, accrued fuel-related revenues of approximately $37 million in 2003 and $38 million in 2002 and 2001 were amortized as a reduction of revenues.

The amortization of O&M costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected results of operations through December 31, 2003 when the amortization period ended.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. In connection with the merger, non-recoverable merger costs were expensed in 2003, 2002 and 2001. 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 recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements through December 31, 2003. The deferred merger costs are being amortized over five to eight year recovery periods, depending on the specific terms of the settlement agreements, with the amortization included in depreciation and amortization expense.

The following tables show the deferred merger cost and amortization expense of the applicable subsidiary registrants:

	Merger Cost Deferral December 31, 2003	Amortization Expense for the Year Ended December 31, 2003
	(in millions)	
I&M	$6.7	$1.7
KPCo	2.4	0.6
PSO	3.2	1.9
SWEPCo	2.7	1.2
TCC	6.5	2.6
TNC	1.9	0.8

	Merger Cost Deferral December 31, 2002	Amortization Expense for the Year Ended December 31, 2002
	(in millions)	
I&M	$8.2	$1.7
KPCo	2.9	0.6
PSO	5.0	1.6
SWEPCo	3.9	1.1
TCC	9.1	2.6
TNC	2.7	0.8

	Merger Cost Deferral December 31, 2001	Amortization Expense for the Year Ended December 31, 2001
	(in millions)	
I&M	$9.1	$1.7
KPCo	3.2	0.6
PSO	6.6	1.2
SWEPCo	5.0	1.1
TCC	11.8	2.6
TNC	3.5	0.8

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. As hereinafter summarized, the state settlement agreements provide for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions which began in the third quarter of 2000.

Summary of key provisions of Merger Rate Agreements:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	$221 million rate reduction over 6 years. No base rate increases for 3 years post merger.
Indiana – I&M	$67 million rate reduction over 8 years. Extension of base rate freeze until January 1, 2005. Requires additional annual deposits of $6 million to the nuclear decommissioning trust fund for the years 2001 through 2003.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years. Extension of base rate freeze until January 1, 2005.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years. No base rate increases for 3 years post merger.
Oklahoma – PSO	Rate reductions of approximately $28 million over 5 years. No base rate increase before January 1, 2003.
Arkansas – SWEPCo	Rate reductions of $6 million over 5 years. No base rate increase before June 15, 2003.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years. Base rate cap until June 2005.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

See Note 7, "Commitments and Contingencies" for information on a court decision concerning the merger.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

Prior to 2003, retail customer choice began in four of the eleven state retail jurisdictions (Michigan, Ohio, Texas and Virginia) in which the AEP domestic electric utility companies operate. The following paragraphs discuss significant events occurring related to customer choice and industry restructuring.

OHIO RESTRUCTURING – Affecting CSPCo and OPCo

On June 27, 2002, the Ohio Consumers' Counsel, Industrial Energy Users–Ohio and American Municipal Power–Ohio filed a complaint with the PUCO alleging that CSPCo and OPCo have violated the PUCO's orders regarding implementation of their transition plan and violated the applicable law by failing to participate in an RTO.

The complainants seek, among other relief, an order from the PUCO:

- suspending collection of transition charges by CSPCo and OPCo until transfer of control of their transmission assets has occurred
- requiring the pricing of standard offer electric generation effective January 1, 2006 at the market price used by CSPCo and OPCo in their 1999 transition plan filings to estimate transition costs and
- imposing a $25,000 per company forfeiture for each day AEP fails to comply with its commitment to transfer control of transmission assets to an RTO

Due to FERC, state legislative and regulatory developments, CSPCo and OPCo have been delayed in the implementation of their RTO participation plans. We continue to pursue integration of CSPCo, OPCo and other AEP East companies into PJM. In this regard, on December 19, 2002, CSPCo and OPCo filed an application with the PUCO for approval of the transfer of functional control over certain of their transmission facilities to PJM. In February 2003, the PUCO consolidated the June 2002 complaint with our December application. CSPCo's and OPCo's motion to dismiss the complaint has been denied by the PUCO and the PUCO affirmed that ruling in rehearing. All further action in the consolidated case has been stayed "until more clarity is achieved regarding matters pending at the FERC and elsewhere." Management is currently unable to predict the timing of the AEP East companies' (including CSPCo and OPCo) participation in PJM, the outcome of these proceedings before the PUCO or their impact on results of operations and cash flows.

In October 2002, the PUCO initiated an investigation of the financial condition of Ohio's regulated public utilities. The PUCO's goal is to identify measures available to the PUCO to ensure that the regulated operations of Ohio's public utilities are not impacted by adverse financial consequences of parent or affiliate company unregulated operations and take appropriate corrective action, if necessary. The utilities and other interested parties were requested to provide comments and suggestions by November 12, 2002, with reply comments by November 22, 2002, on the type of information necessary to accomplish the stated goals, the means to gather the required information from the public utilities and potential courses of action that the PUCO could take. In January 2004, the PUCO staff issued a report recommending that the PUCO seek more authority from the Ohio Legislature on this issue. The PUCO has taken no further action in this proceeding. Management is unable to predict the outcome of the PUCO's investigation or its impact on results of operations, cash flows and business practices, if any.

On March 20, 2003, the PUCO commenced a statutorily required investigation concerning the desirability, feasibility and timing of declaring retail ancillary, metering or billing and collection service, supplied to customers within the certified territories of electric utilities, a competitive retail electric service. The PUCO sent out a list of questions and set June 6, 2003 and July 7, 2003 as the dates for initial responses and replies, respectively. CSPCo and OPCo filed comments and responses in compliance with the PUCO's schedule. Management is unable to predict the timing or the outcome of this proceeding or its impact on results of operations or cash flows.

The Ohio Act provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005. The PUCO may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utility's certified territory or that there is a twenty percent switching rate of the incumbent utility's load by customer class. Following the MDP, retail customers will receive distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates. On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rule provides for a Market Based Standard Service Offer which would be a variable rate based on a transparent forward market, daily market, and/or hourly market prices. The rule also requires a fixed-rate Competitive Bidding Process for residential and small nonresidential customers and permits a fixed-rate Competitive Bidding Process for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the Market Based Standard Service Offer or the Competitive Bidding Process. Customers who make no choice will be served pursuant to the Competitive Bidding Process.

On February 9, 2004, CSPCo and OPCo filed their rate stabilization plan with the PUCO addressing rates following the end of the MDP, which ends December 31, 2005. If approved by the PUCO, rates would be established pursuant to the plan for the period from January 1, 2006 through December 31, 2008 instead of the rates discussed in the previous paragraph. The plan is intended to provide rate stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. The plan includes annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo), and the opportunity for additional generation-related increases upon PUCO review and approval. For residential customers, however, if the temporary 5% generation rate discount provided by the Ohio Act were eliminated on June 30, 2004, the fixed increases would be 1.6% for CSPCo and 5.7% for OPCo. The generation-related increases under the plan would be subject to caps. The plan would maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level effective on December 31, 2005. Such rates could be adjusted for specified reasons through a PUCO filing. Transmission charges can be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion, and ancillary services. The plan also provides for continued recovery of transition regulatory assets and deferral of regulatory assets in 2004 and 2005 for RTO costs and carrying costs on required environmental expenditures. A procedural schedule has not been established for this filing. Management cannot predict whether the plan will be approved as submitted, modified by the PUCO, or its impacts on results of operation and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, CSPCo and OPCo are deferring customer choice implementation costs and related carrying costs that are in excess of $20 million per company. The agreements provide for the deferral of these costs as a regulatory asset until the company's next distribution base rate case. The February 2004 filing provides for the continued deferrals of customer choice implementation costs during the rate stabilization plan period. At December 31, 2003, CSPCo has incurred $32 million and deferred $12 million and OPCo has incurred $34 million and deferred $14 million of such costs. Recovery of these regulatory assets will be subject to PUCO review in each company's future Ohio filings for new distribution rates. If the rate stabilization plan is approved, it would defer recovery of these amounts until after the end of the rate stabilization period. Management believes that the customer choice implementation costs were prudently incurred and the deferred amounts should be recoverable in future rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING – Affecting SWEPCo, TCC and TNC

Texas Legislation enacted in 1999 provided the framework and timetable to allow retail electricity competition for all customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007.

The Texas Legislation, among other things:

- provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility;
- provides for an earnings test for each of the years 1999 through 2001 and;
- provides for a 2004 true-up proceeding. See 2004 true-up proceeding discussion below.

The Texas Legislation required vertically integrated utilities to legally separate their generation and retail-related assets from their transmission and distribution-related assets. Prior to 2002, TCC and TNC functionally separated their operations to comply with the Texas Legislation requirements. AEP formed new subsidiaries to act as affiliated REPs for TCC and TNC effective January 1, 2002 (the start date of retail competition). In December 2002, AEP sold the affiliated REPs to an unaffiliated company.

In 1999, TCC filed with the PUCT to securitize $1.27 billion of its retail generation-related regulatory assets and $47 million in other qualified restructuring costs. The PUCT authorized the issuance of up to $797 million of securitization bonds ($949 million of generation-related regulatory assets and $33 million of qualified refinancing costs offset by $185 million of customer benefits for accumulated deferred income taxes). TCC issued its securitization bonds in February 2002. The amount not approved for securitization will be included in regulatory assets/stranded costs in TCC's 2004 true-up proceeding.

TEXAS 2004 TRUE-UP PROCEEDING

A 2004 true-up proceeding will determine the amount and recovery of:

- net stranded generating plant costs and generation-related regulatory assets (stranded costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's ECOM model for 2002 and 2003 (wholesale capacity auction true-up),
- final approved deferred fuel balance,
- unrefunded accumulated excess earnings,
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback) and
- other restructuring true-up items

The PUCT adopted a rule in 2003 regarding the timing of the 2004 true-up proceedings scheduling TNC's filing in May 2004 and TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later.

Stranded Costs and Generation-Related Regulatory Assets

Restructuring legislation required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. TCC is the only AEP subsidiary that has stranded costs under the Texas Legislation. We have elected to use the sale of assets method to determine the market value of all of our generation assets for stranded cost purposes. When completed, the sale of our generation assets will substantially complete the required separation of generation assets from transmission and distribution assets. For purposes of the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

In December 2002, TCC filed a plan of divestiture with the PUCT seeking approval of a sales process for all of its generating facilities. In March 2003, the PUCT dismissed TCC's divestiture filing, determining that it was more appropriate to address allowable valuation methods for the nuclear asset in a rulemaking proceeding. The PUCT approved a rule, in May 2003, which allows the market value obtained by selling nuclear assets to be used in determining stranded costs. Although the PUCT declined to review TCC's proposed sale of assets process, the PUCT has hired a consultant to advise TCC during the sale of the generation assets. TCC's sale of its generating assets will be subject to a review in the 2004 true-up proceeding.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCC's generating capacity in Texas. In order to sell these assets, TCC anticipates retiring first mortgage bonds by making open market purchases or defeasing the bonds. Bids were received for all of TCC's generating plants. In January 2004, TCC agreed to sell its 7.8% ownership interest in the Oklaunion Power Station to an unaffiliated third party for $43 million. The sale of TCC's remaining generation is pending. Additional regulatory approvals will be required to complete the sale of the generation assets including NRC approval of the transfer of our interest in STP.

In the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized and reduced by mitigation including unrefunded excess earnings, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

After the 2004 true-up proceeding, TCC may seek to issue securitization revenue bonds for its stranded costs and recover the costs of the securitization bonds through transmission and distribution rates. Based upon the Oklaunion sale and the bid information for the remaining generation, we recorded an impairment of generating assets of $938 million in December 2003 as a regulatory asset (see Note 10). The recovery of the regulatory asset will be subject to review and approval by the PUCT as a stranded cost in the 2004 true-up proceeding.

Wholesale Capacity Auction True-up

Texas Legislation also requires that electric utilities and their affiliated power generation companies (PGC) offer for sale at auction, in 2002 and 2003 and after, at least 15% of the PGC's Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation. Actual market power prices received in the state mandated auctions will be used to calculate the wholesale capacity auction true-up adjustment for TCC for the 2004 true-up proceeding.

TCC recorded a $480 million regulatory asset and related revenues which represent the quantifiable amount of the wholesale capacity auction true-up for the years 2002 and 2003. In TCC's UCOS proceeding, the PUCT estimated that TCC had negative stranded costs. In its true-up rule, the PUCT determined that the wholesale capacity auction true-up proceeds should be offset against negative stranded costs. However, in March 2003, the Texas Court of Appeals ruled that under the restructuring legislation, other 2004 true-up items, including the wholesale capacity auction true-up regulatory asset, could be recovered regardless of the level of stranded costs.

In the fourth quarter of 2003, the PUCT approved a true-up filing package containing calculation instructions similar to the methodology employed by TCC to calculate the amount recorded for recovery under its wholesale capacity auction true-up. The PUCT will review the $480 million wholesale capacity regulatory asset for recovery as part of the 2004 true-up proceeding.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. In January 2004, the PUCT announced a final ruling in TNC's fuel reconciliation case that established TNC's unrecovered fuel balance, including interest for the ERCOT service territory, at $6.2 million. This balance will be included in TNC's 2004 true-up proceeding. TNC is waiting for a written order from the PUCT, after which it will request a rehearing.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery of fuel balance for inclusion in the 2004 true-up proceeding. In February 2004, an ALJ issued recommendations finding a $205 million over recovery in this fuel proceeding. Management is unable to predict the amount of TCC's fuel over-recovery which will be included in its 2004 true-up proceeding.

See TCC Fuel Reconciliation and TNC Fuel Reconciliation in Note 4 "Rate Matters" for further discussion.

Unrefunded Excess Earnings

The Texas Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined for the three year period were $3 million for SWEPCo, $47 million for TCC and $19 million for TNC. TCC, TNC and SWEPCo challenged the PUCT's treatment of fuel-related deferred income taxes and appealed the PUCT's final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. The District Court's ruling was appealed to the Third Court of Appeals. In August 2003, the Third Court of Appeals reversed the PUCT order and the District Court judgment. The PUCT's request for rehearing of the Appeals Court's decision was denied and the PUCT chose not to appeal the ruling any further. Appeal of the same issue from the PUCT's 2001 order is pending before the District Court. Since an expense and regulatory liability had been accrued in prior years in compliance with the PUCT orders, the companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Court's decision and credited amortization expense during the third quarter of 2003. Pre-tax amounts reversed by company were $5 million for TCC, $3 million for TNC and $1 million for SWEPCo.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order has no additional effect on reported net income but will reduce cash flows for the five-year refund period. The amount to be refunded is recorded as a regulatory liability. Management believes that TCC will have stranded costs and that it was inappropriate for the PUCT to order a refund prior to TCC's 2004 true-up proceeding. TCC appealed the PUCT's refund of excess earnings to the Travis County District Court. That court affirmed the PUCT's decision and further ordered that the refunds be provided to customers. TCC has appealed the decision to the Court of Appeals.

Retail Clawback

The Texas Legislation provides for the affiliated PTB REP serving residential and small commercial customers to refund to its T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. During 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. The PUCT approved TCC's and TNC's filings in December 2003. In 2002, AEP had accrued a regulatory liability of approximately $9 million for the small commercial retail clawback on its REP's books. When the PUCT certified that the REP's in TCC and TNC service territories had reached the 40% threshold, the regulatory liability was no longer required for the small commercial class and was reversed in December 2003. At December 31, 2003, the remaining retail clawback liability was $45.5 million for TCC and $11.8 million for TNC.

When the 2004 true-up proceeding is completed, TCC intends to file to recover PUCT-approved stranded costs and other true-up amounts that are in excess of current securitized amounts, plus appropriate carrying charges and other true-up amounts, through non-bypassable competition transition charge in the regulated T&D rates. TCC may also seek to securitize certain of the approved stranded plant costs and regulatory assets that were not previously recovered through the non-bypassable transition charge. The annual costs of securitization are recovered through a non-bypassable rate surcharge collected by the T&D utility over the term of the securitization bonds.

In the event we are unable, after the 2004 true-up proceeding, to recover all or a portion of our stranded plant costs, generation-related regulatory assets, unrecovered fuel balances, wholesale capacity auction true-up regulatory assets, other restructuring true-up items and costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

MICHIGAN RESTRUCTURING – Affecting I&M

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total rates in Michigan remain unchanged and reflect cost of service. At December 31, 2003, none of I&M's customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Management has concluded that as of December 31, 2003 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

ARKANSAS RESTRUCTURING – Affecting SWEPCo

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCo's Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999.

The reapplication of SFAS 71 had an insignificant effect on results of operations and financial condition. As a result of reapplying SFAS 71, derivative contract gains/losses for transactions within AEP's traditional marketing area allocated to Arkansas will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized.

WEST VIRGINIA RESTRUCTURING – Affecting APCo

APCo reapplied SFAS 71 for its West Virginia (WV) jurisdiction in the first quarter of 2003 after new developments during the quarter prompted an analysis of the probability of restructuring becoming effective.

In 2000, the WVPSC issued an order approving an electricity restructuring plan, which the WV Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the WV legislature made tax law changes necessary to preserve the revenues of state and local governments.

In the 2001 and 2002 legislative sessions, the WV Legislature failed to enact the required legislation that would allow the WVPSC to implement the restructuring plan. Due to this lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring during the summer of 2002.

In the 2003 legislative session, the WV Legislature failed to enact the required tax legislation. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in WV. In March 2003, APCo's outside counsel advised us that restructuring in WV was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's WV generation. APCo has concluded that deregulation of the WV generation business is no longer probable and operations in WV meet the requirements to reapply SFAS 71.

Reapplying SFAS 71 in WV had an insignificant effect on results of operations and financial condition. As a result, derivative contract gains/losses related to transactions within AEP's traditional marketing area allocated to WV will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized. Positions outside AEP's traditional marketing area will continue to be marked-to-market.

7. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation – Affecting APCo, CSPCo, I&M, and OPCo

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

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 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). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

On August 7, 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, an unaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not "routine" maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any non-routine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A remedy trial is scheduled for July 2004.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in the AEP case also vary widely from plant to plant. Further, the Ohio Edison decision is limited to liability issues, and provides no insight as to the remedies that might ultimately be ordered by the Court.

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, an unaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that Federal EPA bears the burden of proof on the issue of whether a practice is "routine maintenance, repair, or replacement" and on whether or not a "significant net emissions increase" results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is "routine within the relevant source category" in determining if it is "routine." Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA has requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for similar alleged violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the Clean Air Act are unconstitutional.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which the AEP subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in the AEP case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in the AEP case.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines "routine maintenance repair and replacement" to include "functionally equivalent equipment replacement." Under the new final rule, replacement of a component within an integrated industrial operation (defined as a "process unit") with a new component that is identical or functionally equivalent will be deemed to be a "routine replacement" if the replacement does not change any of the fundamental design parameters of the process unit, does not result in emissions in excess of any authorized limit, and does not cost more than twenty percent of the replacement cost of the process unit. The new rule is intended to have prospective effect, and will become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003 twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

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

In December 2000, Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the 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 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

NUCLEAR

Nuclear Plants – Affecting I&M and TCC

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement I&M and TCC are partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability – Affecting I&M and TCC

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $10.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $20 million. TCC could be assessed $50 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited. Under an industry-wide program insuring workers at nuclear facilities, I&M and TCC are also obligated for assessments of up to $6 million and $2 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. I&M and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $43 million for I&M and $2 million for TCC which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed in 2004 with increases in required third party financial protection for nuclear incidents.

SNF Disposal – Affecting I&M and TCC

Federal law provides for government responsibility for permanent SNF disposal and assesses 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 $226 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, 2003, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal – Affecting I&M and TCC

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. In November 2003, I&M filed to extend the operating licenses of the two Cook Plant units for up to an additional 20 years. The review of the license extension application is expected to take at least two years. After expiration of the licenses, Cook Plant is expected to be decommissioned using the prompt decontamination and dismantlement (DECON) method. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs for Cook Plant ranges from $821 million to $1,080 million in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $27 million in 2003, 2002 and 2001.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the DECON method. TCC estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC 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 2003, 2002 and 2001, I&M deposited in its decommissioning trust an additional $12 million each year related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in Other Operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in Other Operation expense, interest income of the trusts are recorded in Nonoperating Income and interest expense of the trust funds are included in Interest Charges.

TCC's nuclear decommissioning trust asset and liability are included in held for sale amounts on its Consolidated Balance Sheet.

OPERATIONAL

Construction and Commitments – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The AEP System has substantial construction commitments to support its operations. The following table shows the estimated construction expenditures by company for 2004 – 2006 including amounts for proposed environmental rules:

	(in millions)
AEGCo	$73.3
APCo	1,307.2
CSPCo	391.4
I&M	645.1
KPCo	153.3
OPCo	1,686.4
PSO	296.2
SWEPCo	414.3
TCC	531.2
TNC	179.9

AEP subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The expiration date of the longest fuel contract is 2007 for APCo, 2005 for CSPCo, 2007 for I&M, 2005 for KPCo, 2012 for OPCo, 2014 for PSO and 2006 for SWEPCo. The contracts provide for periodic price adjustments and contain various clauses that would release us from our obligations under certain conditions.

I&M has unit contingent contracts to supply approximately 250 MW of capacity to unaffiliated entities through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

Potential Uninsured Losses – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

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

Power Generation Facility – Affecting OPCo

AEP has agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and lease the Facility to AEP. Juniper will own the Facility and lease it to AEP after construction is completed. AEP will sublease the Facility to The Dow Chemical Company (Dow).

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price which is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA which TEM rejected as non-conforming.

OPCo has entered an agreement with an affiliate that eliminates OPCo's market exposure related to the PPA. AEP has guaranteed this affiliate's performance under the agreement.

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

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM, on February 11, 2004, and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately $17.5 million. TEM may also claim that AEP is not entitled to receive any termination value for the PPA.

Merger Litigation – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region."

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUCHA's single region requirement because it is now technically possible to centrally control the output of power plants across many states. In its ruling, the appeals court said that the SEC failed to support and explain its conclusions that the integration and single region requirements are satisfied.

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

Enron Bankruptcy –Affecting APCo, CSPCo, I&M, KPCo and OPCo

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. We will assert our right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

During 2002 and 2001, AEP expensed a total of $53 million ($34 million net of tax) for our estimated loss from the Enron bankruptcy. The amounts for certain subsidiaries were:

Registrant	Amounts Expensed	Amounts Net of Tax
	(in millions)	
APCo	$5.3	$3.4
CSPCo	2.7	1.8
I&M	2.8	1.8
KPCo	1.1	0.7
OPCo	3.6	2.3

The amount expensed was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Texas Commercial Energy, LLP Lawsuit – Affecting TCC and TNC

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against AEP and four AEP subsidiaries, including TCC and TNC, certain unaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. AEP and its subsidiaries filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. AEP and its subsidiaries intend to file a motion to dismiss the amended complaint and otherwise vigorously defend against the claims.

Energy Market Investigation – Affecting AEP System

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

In March 2003, we received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, we had received an informal data request from the SEC asking that we voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. We responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, it is not expected to have a material effect on results of operations due to a provision recorded in December 2003.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. We are responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

FERC Proposed Standard Market Design – Affecting AEP System

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until the potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation – Affecting AEP System

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

8. GUARANTEES

There are no liabilities recorded for guarantees entered into prior to December 31, 2002 by registrant subsidiaries in accordance with FIN 45. There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002. There is no collateral held in relation to any guarantees and there is no recourse to third parties in the event any guarantees are drawn unless specified below.

Letters of Credit

Certain registrant subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves, and credit enhancements for issued bonds. All of these LOCs were issued in the registrant subsidiaries' ordinary course of business. At December 31, 2003, the maximum future payments of the LOCs include $43 million, $1 million, $5 million and $4 million for TCC, I&M, OPCo and SWEPCo, respectively, with maturities ranging from March 2004 to November 2005. AEP holds all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed under certain conditions, to assume the obligations under capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $58 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2003, the cost to reclaim the mine in 2035 is estimated to be approximately $36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Indemnifications and Other Guarantees

All of the registrant subsidiaries enter into certain types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Registrant subsidiaries cannot estimate the maximum potential exposure for any of these indemnifications entered into prior to December 31, 2002 due to the uncertainty of future events. In 2003 registrant subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual registrant subsidiary. There are no material liabilities recorded for any indemnifications entered into during 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

Certain registrant subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2003, the maximum potential loss by subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Subsidiary	Maximum Potential Loss (in millions)
APCo	$ 1
CSPCo	1
I&M	2
KPCo	1
OPCo	3
PSO	4
SWEPCo	4
TCC	6
TNC	2

See Note 15 "Leases" for disclosure of lease residual value guarantees.

9. SUSTAINED EARNINGS IMPROVEMENT INITIATIVE

In response to difficult conditions in AEP's business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

The registrant subsidiaries recorded termination benefits expense relating to 389 terminated employees totaling $57.9 million pre-tax in the fourth quarter of 2002. Of this amount, the registrant subsidiaries paid $5.0 million to these terminated employees in the fourth quarter of 2002. No additional termination benefits expense related to the SEI initiative was recorded in 2003, and the remaining SEI related payments were made in 2003. The termination benefits expense is classified as Other Operation expense on the registrant subsidiaries' statements of operations. We determined that the termination of the employees under our SEI initiative did not constitute a plan curtailment of any of our retirement benefit plans.

The following table shows the staff reductions, termination benefits expense and the remaining termination benefits expense accrual as of December 31, 2002:

	Total Number of Terminated Employees	Total Expense Recorded in 2002 (in millions)	Total Termination Benefits Accrued at 12/31/02 (in millions)
AEGCo	-	$ 0.3	$ 0.3
APCo	93	13.1	12.2
CSPCo	19	5.0	4.5
I&M	146	15.0	13.1
KPCo	16	2.6	2.5
OPCo	33	7.5	7.1
PSO	17	3.1	3.0
SWEPCo	8	3.3	3.1
TCC	37	6.0	5.5
TNC	20	2.0	1.6

10. ACQUISITIONS, DISPOSITIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

ACQUISITIONS

2001

SWEPCo purchased the Dolet Hills mining operations and assumed the existing mine reclamation liabilities at its jointly owned lignite reserves in Louisiana during 2001. Management recorded the assets acquired and liabilities assumed at their estimated fair values in accordance with APB Opinion No. 16 and SFAS 141 as appropriate based on currently available information and on current assumptions as to future operations.

DISPOSITIONS

2003

Water Heater Assets – APCo, CSPCo, I&M, KPCo and OPCo

APCo, CSPCo, I&M, KPCo and OPCo participated in a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale. We sold our water heater rental program and recorded a pre-tax loss in the first quarter of 2003 based upon final terms of the sale agreement. We provided for pre-tax charges in the fourth quarter 2002 based on an estimated sales price. See below for amounts by company:

Subsidiary Company	Asset Impairment Charge Recorded in Fourth Quarter 2002 (Pre-tax)	Lease Prepayment Penalty Recorded in Fourth Quarter 2002 (Pre-tax)	Loss on Sale Recorded in First Quarter 2003 (Pre-tax)
		(in millions)	
APCo	$0.050	$0.062	$0.056
CSPCo	0.615	0.758	0.740
I&M	0.643	0.792	0.787
KPCo	0.011	0.011	0.011
OPCo	1.757	2.163	2.165

Ft. Davis Wind Farm – TNC

In the 1990's TNC developed a 6MW facility wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002 TNC's engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility is expected to be completed during 2004. An estimated pre-tax loss on abandonment of $4.7 million was recorded in December 2002. The loss was recorded in Asset Impairments on TNC's Statements of Operations.

<u>2001</u>

Coal Mines – OPCo

In July 2001, OPCo sold coal mines in Ohio and West Virginia and agreed to purchase approximately 34 million tons of coal from the purchaser of the mines through 2008. The sale had a nominal impact on OPCo's results of operations and cash flows.

ASSETS HELD FOR SALE

Texas Plants – TCC and TNC

In September 2002, AEP indicated to ERCOT its intent to deactivate 16 gas-fired power plants (8 TCC plants and 8 TNC plants). ERCOT subsequently conducted reliability studies, which determined that seven plants (4 TCC plants and 3 TNC plants) would be required to ensure reliability of the electricity grid. As a result of those studies, ERCOT and AEP mutually agreed to enter into reliability must run (RMR) agreements, which expired in December 2002, and were subsequently renewed through December 2003. However, certain contractual provisions provided ERCOT with a 90-day termination clause, if the contracted facility was no longer needed to ensure reliability of the electricity grid. With ERCOT's approval, AEP proceeded with its planned deactivation of the remaining nine plants. In August 2003, pursuant to contractual terms, ERCOT provided notification to AEP of its intent to cancel a RMR agreement at one of the TNC plants. Upon termination of the agreement, AEP proceeded with its planned deactivation of the plant. In December 2003, AEP and ERCOT mutually agreed to new RMR contracts at six plants (4 TCC plants and 2 TNC plants) through December 2004, subject to ERCOT's 90-day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate TNC plants, a write-down of utility assets of approximately $34.2 million (pre-tax) was recorded in Asset Impairments expense during the third quarter 2002 on TNC's Statements of Operations. The decision to deactivate the TCC plants resulted in a write-down of utility assets of approximately $95.6 million (pre-tax), which was deferred and recorded in Regulatory Assets during the third quarter 2002 in TCC's Consolidated Balance Sheets.

During the fourth quarter 2002, evaluations continued as to whether assets remaining at the deactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional asset impairment charge to Asset Impairments expense of $3.9 million (pre-tax) in the fourth quarter 2002. In addition, TNC recorded related inventory write-downs of $2.6 million ($1.2 million of fuel inventory in Fuel for Electric Generation expense and $1.4 million of materials and supplies recorded in Other Operation expense). Similarly, TCC recorded an additional asset impairment write-down of $6.7 million (pre-tax), which was deferred and recorded in Regulatory Assets Designated for Securitization in the fourth quarter 2002. TCC also recorded related inventory write-downs of $14.9 million which was deferred and recorded in Regulatory Assets in the fourth quarter 2002.

The total Texas plant asset impairment of $38.1 million in 2002 related to TNC is included in Asset Impairments expense in TNC's Statements of Operations.

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as RMR status. During the fourth quarter of 2003, after receiving bids from interested buyers, TCC recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to assets held for sale. In accordance with Texas legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the 2004 Texas true-up proceeding. See Texas Restructuring section of Note 6 "Customer Choice and Industry Restructuring" for further discussion of the divestiture plan, anticipated timeline and true-up proceeding.

The assets and liabilities of the entities held for sale at December 31, 2003 and 2002 are as follows:

December 31, 2003	Texas Plants (TCC) (in millions)
Assets:	
Current Assets	$57
Property, Plant and Equipment, Net	797
Regulatory Assets	49
Nuclear Decommissioning Trust Fund	125
Total Assets Held for Sale	$1,028
Liabilities:	
Regulatory Liabilities – Other	$9
Other Noncurrent Liabilities	219
Total Liabilities Held for Sale	$228

December 31, 2002	Texas Plants (TCC) (in millions)
Assets:	
Current Assets	$70
Property, Plant and Equipment, Net	1,647
Nuclear Decommissioning Trust Fund	98
Total Assets Held for Sale	$1,815
Liabilities:	
Deferred Credits and Other	$9
Total Liabilities Held for Sale	$9

ASSETS HELD AND USED

Blackhawk Coal Company – I&M

Blackhawk Coal Company (Blackhawk) is a wholly-owned subsidiary of I&M and was formerly engaged in coal mining operations until they ceased due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the value of the investment needed to be written down based on an updated valuation reflecting management's decision not to pursue development of potential gas reserves. As a result, a $10.4 million charge was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Nonoperating Expenses in I&M's Consolidated Statements of Income.

11. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWPECo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees in the U.S.

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 at the plan's measurement date of December 31, 2003, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	2003	2002	2003	2002
	(in millions)			
Change in Benefit Obligation:				
Obligation at January 1	$3,583	$3,292	$1,877	$1,645
Service Cost	80	72	42	34
Interest Cost	233	241	130	114
Participant Contributions	-	-	14	13
Plan Amendments	-	(2)	-	-
Actuarial (Gain) Loss	91	258	192	152
Benefit Payments	(299)	(278)	(92)	(81)
Obligation at December 31	$3,688	$3,583	$2,163	$1,877
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$2,795	$3,438	$723	$711
Actual Return on Plan Assets	619	(371)	122	(57)
Company Contributions (a)	65	6	183	137
Participant Contributions	-	-	14	13
Benefit Payments (a)	(299)	(278)	(92)	(81)
Fair Value of Plan Assets at December, 31	$3,180	$2,795	$950	$723
Funded Status:				
Funded Status at December 31	$(508)	$(788)	$(1,213)	$(1,154)
Unrecognized Net Transition (Asset) Obligation	2	(7)	206	233
Unrecognized Prior Service Cost	(12)	(13)	6	6
Unrecognized Actuarial (Gain) Loss	797	1,020	977	896
Net Asset (Liability) Recognized	$279	$212	$(24)	$(19)

(a) AEP contributions and benefit payments include only those amounts contributed directly to or paid directly from plan assets.

Accumulated Benefit Obligation:	2003	2002
	(in millions)	
U.S. Qualified Pension Plans	$3,549	$3,456
U.S. Nonqualified Pension Plans	76	71

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	2003	2002	2003	2002
		(in millions)		
Prepaid Benefit Costs	$325	$255	$-	$-
Accrued Benefit Liability	(46)	(44)	(24)	(19)
Additional Minimum Liability	(723)	(944)	N/A	N/A
Unrecognized Prior Service Costs	39	45	N/A	N/A
Accumulated Other Comprehensive Income	684	900	N/A	N/A
Net Asset (Liability) Recognized	$279	$212	$(24)	$(19)
Increase (Decrease) in Minimum Liability Included in Other Comprehensive Income (Pre-tax)	$(216)	$894	N/A	N/A

N/A = Not Applicable

The asset allocations for the U.S. pension plans at the end of 2003 and 2002, and the target allocation for 2004, by asset category, are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at Yearend 2003	2002
		(in percentage)	
Equity	70	71	67
Fixed Income	28	27	32
Cash and Cash Equivalents	2	2	1
Total	100	100	100

The asset allocations for the U.S. other postretirement benefit plans at the end of 2003 and 2002, and target allocation for 2004, by asset category, are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at Yearend 2003	2002
		(in percentage)	
Equity	70	61	41
Fixed Income	28	36	38
Cash and Cash Equivalents	2	3	21
Total	100	100	100

AEP's investment strategy for the employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk.

The value of the AEP qualified plans' assets increased from $2.795 billion at December 31, 2002 to $3.180 billion at December 31, 2003. The qualified plans paid $292 million in benefits to plan participants during 2003 (nonqualified plans paid $7 million in benefits). AEP's plans remain in an underfunded position (plan assets are less than projected benefit obligations) of $508 million at December 31, 2003. Due to the pension plans currently being underfunded, AEP recorded income in Other Comprehensive Income (OCI) of $154 million, and a reduction in the Deferred Income Tax Asset of $76 million, offset by a reduction to Minimum Pension Liability of $234 million and a reduction in adjustments for unrecognized costs of $4 million. The charge to OCI does not affect earnings or cash flow. Also, due to the current underfunded status of AEP's qualified plans, AEP expects to make cash contributions to the U.S. pension plans of approximately $41 million in 2004.

At December 31, 2003 and 2002, the projected benefit obligation, accumulated benefit obligation, and fair value of U.S. plan assets of the U.S. pension plans with an accumulated benefit obligation in excess of plan assets, were as follows:

End of Year	U.S. Plans 2003	2002
	(in millions)	
Projected Benefit Obligation	$3,688	$3,583
Accumulated Benefit Obligation	3,625	3,527
Fair Value of Plan Assets	3,180	2,795
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	445	732

AEP bases its determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

The weighted-average assumptions as of December 31, used in the measurement of AEP's benefit obligations are shown in the following tables:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2003	2002	2003	2002
	(in percentage)			
Discount Rate	6.25	6.75	6.25	6.75
Rate of Compensation Increase	3.7	3.7	N/A	N/A

In determining the discount rate in the calculation of future pension obligations AEP reviews the interest rates of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. As a result of a decrease in this benchmark rate during 2003, AEP determined that a decrease in its discount rate from 6.75% at December 31, 2002 to 6.25% at December 31, 2003 was appropriate.

The rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 8.5% per year, with an average increase of 3.7%.

Information about the expected cash flows for the U.S. pension (qualified and non-qualified) and other postretirement benefit plans is as follows:

	U.S. Pension Plans	U.S. Other Postretirement Benefit Plans
	(in millions)	
Employer Contributions		
2003	$65	$183
2004 (expected)	41	180

The table below reflects the total benefits expected to be paid from the plan or from AEP assets, including both AEP's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and other postretirement benefits are as follows:

	U.S. Pension Benefits	U.S. Other Postretirement Benefit Plans
	(in millions)	
2004	$293	$106
2005	300	114
2006	310	123
2007	325	132
2008	335	140
Years 2009 to 2013, in Total	1,840	836

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater. The contribution to the other postretirement benefit plans' trusts is generally based on the amount of the other postretirement benefit plans' expense for accounting purposes and is provided for in agreements with state regulatory authorities.

The following table provides the components of AEP's net periodic benefit cost (credit) for the plans for fiscal years 2003, 2002 and 2001:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(in millions)					
Service Cost	$80	$72	$69	$42	$34	$30
Interest Cost	233	241	232	130	114	114
Expected Return on Plan Assets	(318)	(337)	(338)	(64)	(62)	(61)
Amortization of Transition (Asset) Obligation	(8)	(9)	(8)	28	29	30
Amortization of Prior-service Cost	(1)	(1)	-	-	-	-
Amortization of Net Actuarial (Gain) Loss	11	(10)	(24)	52	27	18
Net Periodic Benefit Cost (Credit)	(3)	(44)	(69)	188	142	131
Curtailment Loss	-	-	-	-	-	1
Net Periodic Benefit Cost (Credit) After Curtailments	$(3)	$(44)	$(69)	$188	$142	$132

The following table provides the net periodic benefit cost (credit) for the plans by the following AEP registrant subsidiaries for fiscal years 2003, 2002 and 2001:

	Pension Plans			Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(thousands)					
APCo	$(5,202)	$(9,988)	$(13,645)	$33,618	$25,107	$22,810
CSPCo	(5,399)	(8,328)	(10,624)	14,684	11,494	10,328
I&M	(812)	(4,206)	(7,805)	22,999	17,608	15,077
KPCo	(566)	(1,406)	(1,922)	4,043	2,986	2,438
OPCo	(6,621)	(11,360)	(14,879)	28,143	22,608	34,444
PSO	(291)	(3,819)	(2,480)	9,885	8,436	6,187
SWEPCo	1,012	(2,245)	(3,051)	10,264	8,371	6,399
TCC	(123)	(4,786)	(3,411)	12,951	10,733	8,214
TNC	606	(1,104)	(1,644)	5,875	4,798	3,729

The weighted-average assumptions as of January 1, used in the measurement of AEP's benefit costs are shown in the following tables:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(in percentage)					
Discount Rate	6.75	7.25	7.50	6.75	7.25	7.50
Expected Return on Plan Assets	9.00	9.00	9.00	8.75	8.75	8.75
Rate of Compensation Increase	3.7	3.7	3.2	N/A	N/A	N/A

The expected return on plan assets for 2003 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was reduced to 8.35%.

The assumptions used for other postretirement benefit plan measurement purposes are shown below:

Health Care Trend Rates:	2003	2002
	(in percentage)	
Initial	10.0	10.0
Ultimate	5.0	5.0
Year Ultimate Reached	2008	2008

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$26	$(21)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	315	(257)

AEP has not yet determined the impact of the Medicare Prescription Drug Improvement and Modernization Act of 2003 on its other postretirement benefit plans' accumulated benefit obligation and periodic benefit cost. See FASB Staff Position No. 106-1 in Note 2 for additional information on the potential impact on AEP's results of operations, cash flows and financial condition.

Retirement Savings Plan

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in an AEP sponsored defined contribution retirement savings plan eligible to substantially all non-United Mine Workers of America (UMWA) employees. This plan includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. Prior to January 1, 2003, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participated in two large AEP sponsored defined contribution retirement savings plans. Beginning in 2001 and continuing with the single merged plan, contributions to the plans increased from 50% to 75% of the first 6% of eligible employee compensation.

The following table provides the cost for contributions to the retirement savings plans by the following AEP registrant subsidiaries for fiscal years 2003, 2002 and 2001:

	2003	2002 (in thousands)	2001
APCo	$6,450	$ 6,722	$7,031
CSPCo	2,745	2,784	2,789
I&M	7,616	8,039	7,833
KPCo	1,042	1,043	1,016
OPCo	5,719	5,785	6,398
PSO	2,350	2,260	2,235
SWEPCo	3,418	3,170	2,896
TCC	2,757	3,054	3,046
TNC	1,332	1,574	1,558

Other UMWA Benefits

OPCo provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UWMA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by AEP and benefits are paid from AEP's general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2003, 2002 and 2001. In July 2001, OPCo sold certain coal mines in Ohio and West Virginia.

12. BUSINESS SEGMENTS

All of AEP's registrant subsidiaries have one reportable segment. The one reportable segment is a vertically integrated electricity generation, transmission and distribution business except AEGCo, an electricity generation business. All of the registrants' other activities are insignificant. The registrant subsidiaries' operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on the business process, cost structures and operating results.

13. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

Derivatives and Hedging

In the first quarter of 2001, we adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Registrant Subsidiaries recorded a transition adjustment to Accumulated Other Comprehensive Income (Loss) on January 1, 2001 in connection with the adoption of SFAS 133. Derivatives included in the transition adjustment are interest rate swaps, foreign currency swaps and commodity swaps, options and futures.

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position at fair value. Registrant subsidiaries accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies, and has been designated, as part of a hedging relationship and further, on the type of hedging relationship. Registrant subsidiaries designate the hedging instrument, based on the exposure being hedged, as a fair value hedge or a cash flow hedge. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. These contracts are not reported at fair value, as otherwise required by SFAS 133.

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), registrant subsidiaries recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Revenues in the Consolidated Statements of Operations during the period of change. For cash flow hedges (i.e., hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), registrant subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Other Accumulated Comprehensive Income and subsequently reclassify it to Revenues in the Consolidated Statements of Operations when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in revenues during the period of change. Registrant subsidiaries recognize any ineffective portions of in revenues immediately during the period of change.

Fair Value Hedging Strategies

Certain registrant subsidiaries enter into interest rate forward and swap transactions for interest rate risk exposure management purposes. The interest rate forward and swap transactions effectively modifies our exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. Registrant subsidiaries do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

Certain registrant subsidiaries enter into forward contracts to protect against the reduction in value of forecasted cash flows resulting from transactions denominated in foreign currencies. When the dollar strengthens significantly against the foreign currencies, the decline in value of future foreign currency revenue is offset by gains in the value of the forward contracts designated as cash flow hedges. Conversely, when the dollar weakens, the increase in the value of future foreign currency cash flows is offset by losses in the value of forward contracts. Registrant subsidiaries do not hedge all foreign currency exposure.

Certain registrant subsidiaries enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. These transactions effectively modify our exposure to interest risk by converting a portion of our floating-rate debt to a fixed rate. Registrant subsidiaries do not hedge all interest rate exposure.

Registrant subsidiaries enter into forward and swap transactions for the purchase and sale of electricity to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impact of commodity price changes and, where appropriate, enter into contracts to protect margin for a portion of future sales and generation revenues. Registrant Subsidiaries do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) related to the effect of adopting SFAS 133 for derivative contracts that qualify as cash flow hedges at December 31, 2003:

	(in thousands)
APCo	
Beginning Balance, January 1, 2003	$(1,920)
Effective portion of changes in fair value	(448)
Reclasses from AOCI to net income	799
Ending Balance, December 31, 2003	$(1,569)
CSPCo	
Beginning Balance, January 1, 2003	$(267)
Effective portion of changes in fair value	194
Reclasses from AOCI to net income	275
Ending Balance, December 31, 2003	$202
I&M	
Beginning Balance, January 1, 2003	$(286)
Effective portion of changes in fair value	209
Reclasses from AOCI to net income	299
Ending Balance, December 31, 2003	$222

KPCo	
Beginning Balance, January 1, 2003	$322
Effective portion of changes in fair value	75
Reclasses from AOCI to net income	23
Ending Balance, December 31, 2003	$420
OPCo	
Beginning Balance, January 1, 2003	$(738)
Effective portion of changes in fair value	256
Reclasses from AOCI to net income	379
Ending Balance, December 31, 2003	$(103)
PSO	
Beginning Balance, January 1, 2003	$(42)
Effective portion of changes in fair value	18
Reclasses from AOCI to net income	180
Ending Balance, December 31, 2003	$156
SWEPCo	
Beginning Balance, January 1, 2003	$(48)
Effective portion of changes in fair value	21
Reclasses from AOCI to net income	211
Ending Balance, December 31, 2003	$184
TCC	
Beginning Balance, January 1, 2003	$(36)
Effective portion of changes in fair value	(1,931)
Reclasses from AOCI to net income	139
Ending Balance, December 31, 2003	$(1,828)
TNC	
Beginning Balance, January 1, 2003	$(15)
Effective portion of changes in fair value	(641)
Reclasses from AOCI to net income	55
Ending Balance, December 31, 2003	$(601)

The following table approximates net gain (losses) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2003 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is five years.

	(in thousands)
APCo	$1,325
CSPCo	940
I&M	1,031
KPCo	466
OPCo	1,231
PSO	724
SWEPCo	853
TCC	(1,413)
TNC	(435)

Financial Instruments

Market Valuation of Non-Derivative Financial Instrument

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange. The book values and fair values of significant financial instruments for registrant subsidiaries at December 31, 2003 and 2002 are summarized in the following tables.

	2003		2002	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)		(in thousands)	
AEGCo				
Long-term Debt	$44,811	$47,882	$44,802	$48,103
APCo				
Long-term Debt	$1,864,081	$1,926,518	$1,893,861	$1,953,087
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	5,360	5,287	10,860	9,774
CSPCo				
Long-term Debt	$897,564	$938,595	$621,626	$643,715
I&M				
Long-term Debt	$1,339,359	$1,400,937	$1,617,062	$1,673,363
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	63,445	63,293	64,945	58,948
KPCo				
Long-term Debt	$427,602	$439,636	$466,632	$475,455
OPCo				
Long-term Debt	$2,039,940	$2,117,131	$1,067,314	$1,095,197
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	7,250	7,214	8,850	7,965
PSO				
Long-term Debt	$574,298	$589,956	$545,437	$570,761
Trust Preferred Securities (b)	-	-	75,000	75,900
SWEPCo				
Long-term Debt	$884,308	$917,982	$693,448	$727,085
Trust Preferred Securities (b)	-	-	110,000	110,880
TCC				
Long-term Debt	$2,291,625	$2,393,468	$1,438,565	$1,522,373
Trust Preferred Securities (b)	-	-	136,250	136,959
TNC				
Long-term Debt	$356,754	$374,420	$132,500	$144,060

(a) See Registrants Statements of Capitalization for the effect of SFAS 150 in 2003.
(b) See Note 16 on Trust Preferred Securities.

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments are classified as available for sale for decommissioning (I&M, TCC) and SNJ disposal for I&M. I&M reports trusts in "Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds" on the Consolidated Balance Sheets. TCC reports trusts in "Assets Held for Sale – Texas Generating Plants" on their Consolidated Balance Sheets. The following table provides fair values, cost basis and net unrealized gains or losses at December 31:

	I&M (in thousands)		TCC (in thousands)	
	2003	2002	2003	2002
Fair Value	$982,400	$870,700	$125,400	$98,400
Cost Basis	$900,000	$823,900	$94,800	$84,600

	I&M 2003	2002 (in thousands)	2001	TCC 2003	2002 (in thousands)	2001
Net Unrealized Holding Gain (Loss)	$35,500	$(25,400)	$(8,300)	$16,700	$(7,500)	$(3,000)

14. INCOME TAXES

The details of the registrant subsidiaries income taxes before extraordinary items and cumulative effect of accounting changes as reported are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo
Year Ended December 31, 2003			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$7,481	$84,449	$83,469	$58,190	$(7,840)
Deferred	(5,838)	37,024	3,982	66	21,183
Deferred Investment Tax Credits	-	(1,884)	(3,041)	(7,330)	(1,168)
Total	1,643	119,589	84,410	50,926	12,175
Charged (Credited) to Nonoperating Income (net):					
Current	(196)	(646)	(2,183)	5,283	(1,382)
Deferred	-	(12,461)	(8,496)	(14,960)	(1,076)
Deferred Investment Tax Credits	(3,354)	(1,262)	(69)	(101)	(42)
Total	(3,550)	(14,369)	(10,748)	(9,778)	(2,500)
Total Income Tax as Reported	$(1,907)	$105,220	$73,662	$41,148	$9,675

Year Ended December 31, 2003	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$116,316	$55,834	$51,564	$88,530	$33,822
Deferred	32,191	(17,036)	7,230	14,769	(5,113)
Deferred Investment Tax Credits	(2,493)	(1,790)	(4,326)	(5,207)	(1,520)
Total	146,014	37,008	54,468	98,092	27,189
Charged (Credited) to Nonoperating Income (net):					
Current	708	(1,566)	(6,108)	2,456	1,454
Deferred	(7,709)	2,395	2,712	4,624	1,620
Deferred Investment Tax Credits	(614)	-	-	-	-
Total	(7,615)	829	(3,396)	7,080	3,074
Total Income Tax as Reported	$138,399	$37,837	$51,072	$105,172	$30,263

Year Ended December 31, 2002	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$6,607	$99,140	$81,538	$66,063	$680
Deferred	(5,028)	17,626	25,771	(19,870)	9,451
Deferred Investment Tax Credits	2	(3,229)	(3,095)	(7,340)	(1,173)
Total	1,581	113,537	104,214	38,853	8,958
Charged (Credited) to Nonoperating Income (net):					
Current	(173)	(354)	9,442	3,435	1,583
Deferred	-	(849)	(2,479)	2,949	388
Deferred Investment Tax Credits	(3,363)	(1,408)	(174)	(400)	(67)
Total	(3,536)	(2,611)	6,789	5,984	1,904
Total Income Tax as Reported	$(1,955)	$110,926	$111,003	$44,837	$10,862

Year Ended December 31, 2002	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$86,026	$(49,673)	$41,354	$30,494	$109
Deferred	30,048	75,659	(3,134)	113,726	(10,652)
Deferred Investment Tax Credits	(2,493)	(1,791)	(4,524)	(5,206)	(1,271)
Total	113,581	24,195	33,696	139,014	(11,814)
Charged (Credited) to Nonoperating Income (net):					
Current	2,732	(1,812)	1,772	3,223	1,334
Deferred	15,962	-	-	(71)	(1,623)
Deferred Investment Tax Credits	(684)	-	-	-	-
Total	18,010	(1,812)	1,772	3,152	(289)
Total Income Tax as Reported	$131,591	$22,383	$35,468	$142,166	$(12,103)

Year Ended December 31, 2001	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$9,126	$71,623	$88,013	$107,286	$7,726
Deferred	(6,224)	27,198	14,923	(45,785)	2,812
Deferred Investment Tax Credits	-	(3,237)	(3,899)	(7,377)	(1,180)
Total	2,902	95,584	99,037	54,124	9,358
Charged (Credited) to Nonoperating Income (net):					
Current	(56)	(19,165)	(13,803)	(10,590)	(2,726)
Deferred	-	21,832	17,885	16,580	3,481
Deferred Investment Tax Credits	(3,414)	(1,528)	(159)	(947)	(71)
Total	(3,470)	1,139	3,923	5,043	684
Total Income Tax as Reported	$(568)	$96,723	$102,960	$59,167	$10,042

Year Ended December 31, 2001	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$(62,298)	$53,030	$77,965	$190,672	$19,424
Deferred	166,166	(16,726)	(31,396)	(72,568)	(11,891)
Deferred Investment Tax Credits	(2,495)	(1,791)	(4,453)	(5,208)	(1,271)
Total	101,373	34,513	42,116	112,896	6,262
Charged (Credited) to Nonoperating Income (net):					
Current	(21,600)	352	542	(1,749)	(691)
Deferred	20,014	-	-	-	-
Deferred Investment Tax Credits	(794)	-	-	-	-
Total	(2,380)	352	542	(1,749)	(691)
Total Income Tax as Reported	$98,993	$34,865	$42,658	$111,147	$5,571

Shown below is a reconciliation for each registrant subsidiary of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory rate, and the amount of income taxes reported.

	AEGCo	APCo	CSPCo	I&M	KPCo
Year Ended December 31, 2003		(in thousands)			
Net Income	$7,964	$280,040	$200,430	$86,388	$32,330
Cumulative Effect of Accounting Change	-	(77,257)	(27,283)	3,160	1,134
Income Taxes	(1,907)	105,220	73,662	41,148	9,675
Pre-Tax Income	$6,057	$308,003	$246,809	$130,696	$43,139
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$2,120	$107,801	$86,383	$45,744	$15,099
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	371	9,263	2,220	19,288	1,538
Nuclear Fuel Disposal Costs	-	-	-	(6,465)	-
Allowance for Funds Used During Construction	(1,053)	(2,048)	(232)	(4,127)	(851)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(2,280)	(7)	(693)	(735)
Investment Tax Credits (net)	(3,354)	(3,146)	(3,110)	(7,431)	(1,210)
State Income Taxes	372	1,123	(3,074)	4,634	(58)
Other	(737)	(5,493)	(8,518)	(10,199)	(4,108)
Total Income Taxes as Reported	$(1,907)	$105,220	$73,662	$41,148	$9,675
Effective Income Tax Rate	N.M.	34.2%	29.8%	31.5%	22.4%

	OPCo	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2003		(in thousands)			
Net Income	$375,663	$53,891	$98,141	$217,669	$58,557
Cumulative Effect of Accounting Change	(124,632)	-	(8,517)	(122)	(3,071)
Extraordinary Loss	-	-	-	-	177
Income Taxes	138,399	37,837	51,072	105,172	30,263
Pre-Tax Income	$389,430	$91,728	$140,696	$322,719	$85,926
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$136,301	$32,105	$49,244	$112,952	$30,074
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	4,388	1,166	834	486	286
Investment Tax Credits (net)	(3,107)	(1,791)	(4,326)	(5,207)	(1,521)
State Income Taxes	4,717	2,886	9,723	(10,434)	3,078
Other	(3,900)	3,471	(4,403)	7,375	(1,654)
Total Income Taxes as Reported	$138,399	$37,837	$51,072	$105,172	$30,263
Effective Income Tax Rate	35.5%	41.2%	36.3%	32.6%	35.2%

Year Ended December 31, 2002	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Net Income	$7,552	$205,492	$181,173	$73,992	$20,567
Income Taxes	(1,955)	110,926	111,003	44,837	10,862
Pre-Tax Income	$5,597	$316,418	$292,176	$118,829	$31,429
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$1,959	$110,746	$102,262	$41,590	$11,000
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	286	3,082	2,899	21,812	2,057
Nuclear Fuel Disposal Costs	-	-	-	(3,087)	-
Allowance for Funds Used During Construction	(1,136)	-	-	(3,453)	-
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	(735)
Investment Tax Credits (net)	(3,361)	(4,637)	(3,270)	(7,740)	(1,240)
State Income Taxes	335	6,469	11,387	124	1,058
Other	(412)	(4,734)	(2,275)	(4,409)	(1,278)
Total Income Taxes as Reported	$(1,955)	$110,926	$111,003	$44,837	$10,862
Effective Income Tax Rate	N.M.	35.1%	38.0%	37.7%	34.6%

Year Ended December 31, 2002	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Net Income (Loss)	$220,023	$41,060	$82,992	$275,941	$(13,677)
Income Taxes	131,591	22,383	35,468	142,166	(12,103)
Pre-Tax Income (Loss)	$351,614	$63,443	$118,460	$418,107	$(25,780)
Income Tax on Pre-Tax Income (Loss) at Statutory Rate *(35%)*	$123,065	$22,205	$41,461	$146,337	$(9,023)
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	4,227	(583)	(2,790)	(295)	(32)
Investment Tax Credits (net)	(3,177)	(1,791)	(4,524)	(5,207)	(1,271)
State Income Taxes	18,051	2,639	3,987	2,202	(1,577)
Other	(10,575)	(87)	(2,666)	(871)	(200)
Total Income Taxes as Reported	$131,591	$22,383	$35,468	$142,166	$(12,103)
Effective Income Tax Rate	37.4%	35.3%	29.9%	34.0%	46.9%

Year Ended December 31, 2001	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Net Income	$7,875	$161,818	$161,876	$75,788	$21,565
Extraordinary Loss	-	-	30,024	-	-
Income Taxes	(568)	96,723	102,960	59,167	10,042
Pre-Tax Income	$7,307	$258,541	$294,860	$134,955	$31,607
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$2,557	$90,489	$103,201	$47,234	$11,062
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	230	2,977	2,757	21,224	1,581
Nuclear Fuel Disposal Costs	-	-	-	(3,292)	-
Allowance for Funds Used During Construction	(1,078)	-	-	(1,606)	-
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	(420)
Investment Tax Credits (net)	(3,414)	(4,765)	(4,058)	(8,324)	(1,252)
State Income Taxes	1,050	9,613	5,727	6,137	318
Other	(287)	(1,591)	(4,667)	(2,206)	(1,247)
Total Income Taxes as Reported	$(568)	$96,723	$102,960	$59,167	$10,042
Effective Income Tax Rate	N.M.	37.4%	34.9%	43.8%	31.8%

Year Ended December 31, 2001	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Net Income	$147,445	$57,759	$89,367	$182,278	$12,310
Extraordinary Loss	18,348	-	-	-	-
Income Taxes	98,993	34,865	42,658	111,147	5,571
Pre-Tax Income	$264,786	$92,624	$132,025	$293,425	$17,881
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$92,675	$32,418	$46,209	$102,699	$6,258
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	7,972	1,127	(501)	8,477	1,463
Investment Tax Credits (net)	(3,289)	(1,791)	(4,453)	(5,207)	(1,271)
State Income Taxes	9,752	5,137	5,451	9,652	1,283
Other	(8,117)	(2,026)	(4,048)	(4,474)	(2,162)
Total Income Taxes as Reported	$98,993	$34,865	$42,658	$111,147	$5,571
Effective Income Tax Rate	37.4%	37.6%	32.3%	37.9%	31.2%

The following tables show the elements of the net deferred tax liability and the significant temporary differences for each registrant subsidiary:

December 31, 2003	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Deferred Tax Assets	$79,545	$237,873	$122,453	$695,037	$44,413
Deferred Tax Liabilities	(103,874)	(1,041,228)	(580,951)	(1,032,413)	(256,534)
Net Deferred Tax Liabilities	$(24,329)	$(803,355)	$(458,498)	$(337,376)	$(212,121)
Property Related Temporary Differences	$(62,271)	$(623,126)	$(357,980)	$(74,501)	$(151,404)
Amounts Due From Customers For Future Federal Income Taxes	6,949	(94,457)	(5,575)	(37,233)	(23,203)
Deferred State Income Taxes	(4,350)	(87,484)	(26,972)	(45,736)	(33,535)
Transition Regulatory Assets	-	(10,799)	(66,002)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	28,047	24,946	13,519	3,345
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	36,916	-	-	24,563	-
Accrued Nuclear Decommissioning Expense	-	-	-	(173,054)	-
Deferred Fuel and Purchased Power	-	24,047	(273)	(19)	496
Deferred Cook Plant Restart Costs	-	-	-	(20,064)	-
Nuclear Fuel	-	-	-	(7,027)	-
All Other (Net)	(1,573)	(39,583)	(26,642)	(17,824)	(7,820)
Net Deferred Tax Liabilities	$(24,329)	$(803,355)	$(458,498)	$(337,376)	$(212,121)

December 31, 2003	OPCo	PSO (in thousands)	SWEPCo	TCC	TNC
Deferred Tax Assets	$192,026	$164,801	$163,457	$298,648	$67,794
Deferred Tax Liabilities	(1,125,608)	(500,235)	(512,521)	(1,543,560)	(180,813)
Net Deferred Tax Liabilities	$(933,582)	$(335,434)	$(349,064)	$(1,244,912)	$(113,019)
Property Related Temporary Differences	$(721,118)	$(297,809)	$(307,023)	$(698,554)	$(118,876)
Amounts Due From Customers For Future Federal Income Taxes	(55,143)	8,728	(5,800)	(191,615)	9,979
Deferred State Income Taxes	(80,573)	(56,413)	(33,651)	(42,044)	(2,946)
Transition Regulatory Assets	(109,150)	-	-	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,470)	-
Nuclear Fuel	-	-	-	(7,240)	-
Deferred Income Taxes on Other Comprehensive Loss	26,280	23,607	23,644	33,316	14,387
Deferred Fuel and Purchased Power	12	(8,460)	(10,996)	(1,738)	(10,143)
Regulatory Assets Designated for Securitization	-	-	-	(281,260)	-
All Other (Net)	6,110	(5,087)	(15,238)	13,769	(5,420)
Net Deferred Tax Liabilities	$(933,582)	$(335,434)	$(349,064)	$(1,244,912)	$(113,019)

December 31, 2002	AEGCo	APCo	CSPCo	I&M	KPCo
		(in thousands)			
Deferred Tax Assets	$82,889	$247,080	$106,597	$436,361	$45,231
Deferred Tax Liabilities	(111,891)	(948,881)	(544,368)	(792,558)	(223,544)
Net Deferred Tax Liabilities	$(29,002)	$(701,801)	$(437,771)	$(356,197)	$(178,313)
Property Related Temporary Differences	$(74,291)	$(555,806)	$(331,166)	$(343,362)	$(127,069)
Amounts Due From Customers For Future Federal Income Taxes	7,626	(58,246)	(8,895)	(38,752)	(20,488)
Deferred State Income Taxes	(5,119)	(77,693)	(23,448)	(52,528)	(28,722)
Transition Regulatory Assets	-	(28,735)	(71,752)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	38,823	31,961	21,800	5,089
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	38,866	-	-	25,860	-
Accrued Nuclear Decommissioning Expense	-	-	-	65,856	-
Deferred Fuel and Purchased Power	-	(1,878)	(273)	(13,144)	415
Deferred Cook Plant Restart Costs	-	-	-	(14,000)	-
Nuclear Fuel	-	-	-	(5,153)	-
All Other (Net)	3,916	(18,266)	(34,198)	(2,774)	(7,538)
Net Deferred Tax Liabilities	$(29,002)	$(701,801)	$(437,771)	$(356,197)	$(178,313)

December 31, 2002	OPCo	PSO	SWEPCo	TCC	TNC
		(in thousands)			
Deferred Tax Assets	$189,281	$141,571	$158,925	$164,343	$62,211
Deferred Tax Liabilities	(983,668)	(482,967)	(499,989)	(1,425,595)	(179,732)
Net Deferred Tax Liabilities	$(794,387)	$(341,396)	$(341,064)	$(1,261,252)	$(117,521)
Property Related Temporary Differences	$(620,019)	$(303,888)	$(315,821)	$(709,246)	$(127,038)
Amounts Due From Customers For Future Federal Income Taxes	(53,256)	9,490	(4,078)	(198,595)	5,726
Deferred State Income Taxes	(46,990)	(57,911)	(48,372)	(66,333)	(4,080)
Transition Regulatory Assets	(131,833)	-	-	-	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,117)	-
Nuclear Fuel	-	-	-	(7,023)	-
Deferred Income Taxes on Other Comprehensive Loss	39,246	29,332	28,906	39,394	16,565
Deferred Fuel and Purchased Power	540	(28,696)	3,192	2,655	(9,933)
Regulatory Assets Designated For Securitization	-	-	-	(310,410)	-
All Other (Net)	17,925	10,277	(4,891)	(10,577)	1,239
Net Deferred Tax Liabilities	$(794,387)	$(341,396)	$(341,064)	$(1,261,252)	$(117,521)

Registrant subsidiaries have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. Registrant Subsidiaries have received Revenue Agent's Reports from the IRS for the years 1991 through 1996, and have filed protests contesting certain proposed adjustments. Returns for the years 1997 through 2000 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.

Registrant Subsidiaries join in the filing of a consolidated federal income tax return with the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

15. LEASES

Leases of property, plant and equipment are for periods up to 99 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for non-regulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
Year Ended December 31, 2003			(in thousands)			
Lease Payments on						
Operating Leases	$76,322	$6,148	$5,277	$110,714	$1,258	$27,337
Amortization of Capital Leases	269	9,217	4,898	7,370	1,951	9,437
Interest on Capital Leases	-	1,123	899	1,276	148	2,472
Total Lease Rental Costs	$76,591	$16,488	$11,074	$119,360	$3,357	$39,246

	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2003		(in thousands)		
Lease Payments on				
Operating Leases	$4,883	$4,708	$6,360	$2,132
Amortization of Capital Leases	174	1,434	161	83
Interest on Capital Leases	17	899	16	9
Total Lease Rental Costs	$5,074	$7,041	$6,537	$2,224

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
Year Ended December 31, 2002			(in thousands)			
Lease Payments on						
Operating Leases	$76,143	$6,634	$5,209	$110,833	$1,597	$68,816
Amortization of Capital Leases	238	9,729	6,010	8,319	2,171	12,637
Interest on Capital Leases	19	2,240	1,717	2,221	469	4,501
Total Lease Rental Costs	$76,400	$18,603	$12,936	$121,373	$4,237	$85,954

	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2002		(in thousands)		
Lease Payments on				
Operating Leases	$4,403	$3,240	$7,184	$1,981
Amortization of Capital Leases	-	-	-	-
Interest on Capital Leases	-	-	-	-
Total Lease Rental Costs	$4,403	$3,240	$7,184	$1,981

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
Year Ended December 31, 2001			(in thousands)			
Lease Payments on						
Operating Leases	$76,262	$6,142	$7,063	$104,574	$1,191	$63,913
Amortization of Capital Leases	281	12,099	7,206	17,933	2,740	14,443
Interest on Capital Leases	55	3,789	2,396	4,424	808	5,818
Total Lease Rental Costs	$76,598	$22,030	$16,665	$126,931	$4,739	$84,174

Year Ended December 31, 2001	PSO	SWEPCo	TCC	TNC
		(in thousands)		
Lease Payments on Operating Leases	$4,010	$2,277	$5,948	$1,534
Amortization of Capital Leases	-	-	-	-
Interest on Capital Leases	-	-	-	-
Total Lease Rental Costs	$4,010	$2,277	$5,948	$1,534

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

Year Ended December 31, 2003	AEGCo	APCo	CSPCo	I&M	KPCo
		(in thousands)			
Property, Plant and Equipment Under Capital Leases					
Production	$865	$2,758	$7,104	$4,492	$1,138
Distribution	-	-	-	14,589	-
Other	-	55,640	25,345	52,536	11,562
Total Property, Plant and Equipment	865	58,398	32,449	71,617	12,700
Accumulated Amortization	596	33,036	16,828	33,774	7,408
Net Property, Plant and Equipment Under Capital Leases	$269	$25,362	$15,621	$37,843	$5,292
Obligations Under Capital Leases:					
Noncurrent Liability	$182	$16,134	$11,397	$31,315	$3,549
Liability Due Within One Year	87	9,218	4,221	6,528	1,743
Total Obligations Under Capital Leases	$269	$25,352	$15,618	$37,843	$5,292

Year Ended December 31, 2003	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Property, Plant and Equipment Under Capital Leases					
Production	$21,099	$-	$-	$-	$-
Distribution	-	-	-	-	-
Other	53,752	1,176	52,695	1,204	556
Total Property, Plant and Equipment	74,851	1,176	52,695	1,204	556
Accumulated Amortization	40,565	166	31,153	160	83
Net Property, Plant and Equipment Under Capital Leases	$34,286	$1,010	$21,542	$1,044	$473
Obligations Under Capital Leases:					
Noncurrent Liability	$25,064	$558	$18,383	$636	$270
Liability Due Within One Year	9,624	452	3,159	407	203
Total Obligations Under Capital Leases	$34,688	$1,010	$21,542	$1,043	$473

Year Ended December 31, 2002	AEGCo	APCo	CSPCo	I&M	KPCo
		(in thousands)			
Property, Plant and Equipment Under Capital Leases					
Production	$1,793	$3,368	$6,380	$5,728	$1,138
Distribution	-	-	-	14,589	-
Other:					
Mining Assets and Other	-	67,395	46,791	70,140	14,258
Total Property, Plant and Equipment	1,793	70,763	53,171	90,457	15,396
Accumulated Amortization	1,294	37,452	26,551	41,141	8,168
Net Property, Plant and Equipment Under Capital Leases	$499	$33,311	$26,620	$49,316	$7,228
Obligations Under Capital Leases:					
Noncurrent Liability	$301	$23,991	$21,643	$42,619	$5,093
Liability Due Within One Year	200	9,598	5,967	8,229	2,155
Total Obligations Under Capital Leases	$501	$33,589	$27,610	$50,848	$7,248

Year Ended December 31, 2002	OPCo	SWEPCo
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$21,360	$-
Distribution	-	-
Other:		
Mining Assets and Other	103,018	45,699
Total Property, Plant and Equipment	124,378	45,699
Accumulated Amortization	63,810	45,699
Net Property, Plant and Equipment Under Capital Leases	$60,568	$-
Obligations Under Capital Leases:		
Noncurrent Liability	$51,266	$-
Liability Due Within One Year	14,360	-
Total Obligations Under Capital Leases	$65,626	$-

Future minimum lease payments consisted of the following at December 31, 2003:

	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
Capital Leases					
2004	$11,735	$4,959	$10,050	$2,107	$11,046
2005	6,853	4,025	7,478	1,640	8,093
2006	5,183	2,676	6,239	957	7,536
2007	2,664	1,773	12,616	785	5,582
2008	2,645	2,050	3,669	256	3,677
Later Years	1,802	2,096	5,994	116	4,627
Total Future Minimum Lease Payments	30,882	17,579	46,046	5,861	40,561
Less Estimated Interest Element	5,530	1,961	8,203	569	5,874
Estimated Present Value of Future Minimum Lease Payments	$25,352	$15,618	$37,843	$5,292	$34,687

	PSO	SWEPCo	TCC	TNC
	(in thousands)			
Capital Leases				
2004	$492	$4,737	$450	$223
2005	368	4,641	373	188
2006	194	4,533	198	87
2007	46	4,410	86	8
2008	4	4,389	24	1
Later Years	-	4,380	-	2
Total Future Minimum Lease Payments	1,104	27,090	1,131	509
Less Estimated Interest Element	94	5,548	88	36
Estimated Present Value of Future Minimum Lease Payments	$1,010	$21,542	$1,043	$473

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
	(in thousands)					
Noncancellable Operating Leases						
2004	$73,854	$5,998	$5,078	$103,909	$1,209	$12,655
2005	73,854	5,154	4,920	97,447	1,084	11,886
2006	73,854	4,455	2,518	93,993	793	11,576
2007	73,854	3,302	2,205	91,328	771	11,132
2008	73,854	2,394	1,609	90,749	475	10,787
Later Years	1,033,956	6,094	2,726	1,096,567	1,785	66,918
Total Future Minimum Lease Payments	$1,403,226	$27,397	$19,056	$1,573,993	$6,117	$124,954

	PSO	SWEPCo	TCC	TNC
	(in thousands)			
Noncancellable Operating Leases				
2004	$4,684	$5,522	$6,112	$1,964
2005	4,520	6,020	5,886	1,945
2006	4,079	6,844	5,218	1,846
2007	3,424	7,218	4,397	1,532
2008	1,218	7,451	3,950	1,238
Later Years	8,616	17,849	11,272	4,981
Total Future Minimum Lease Payments	$26,541	$50,904	$36,835	$13,506

Gavin Lease

OPCo has entered into an agreement with JMG, an unrelated special purpose entity. JMG has a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from commercial paper, pollution control bonds and other bonds. JMG was formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. JMG owns the Gavin Scrubber and leases it to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease. Payments under the lease agreement are based on JMG's cost of financing (both debt and equity) and include an amortization component plus the cost of administration. OPCo and AEP do not have an ownership interest in JMG and do not guarantee JMG's debt.

At any time during the lease, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber on behalf of JMG. The initial 15-year lease term is non-cancelable. At the end of the initial term, OPCo can renew the lease, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.

On March 31, 2003, OPCo made a prepayment of $90 million under this lease structure. AEP recognizes lease expense on a straight-line basis over the remaining lease term, in accordance with SFAS 13 "Accounting for Leases." The asset will be amortized over the remaining lease term, which ends in the first quarter of 2010.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of AEP's requirement to consolidate JMG, and there was no change in net income due to the consolidation of JMG. Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for on a consolidated basis as an operating lease and has been excluded from the above table of future minimum lease payments.

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee) an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors. The future minimum lease payments for each respective company are $1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, AEGCo and I&M are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.
The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt.

16. FINANCING ACTIVITIES

Trust Preferred Securities

PSO, SWEPCo and TCC have wholly-owned business trusts that have issued trust preferred securities. The trusts which hold mandatorily redeemable trust preferred securities were deconsolidated effective July 1, 2003 due to the implementation of FIN 46. Therefore, $321 million ($75 million PSO, $110 million SWEPCo and $136 million TCC), previously reported at December 31, 2002 as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries, is now reported as two components on the Balance Sheet. The investment in the trust is now reported as Other Investments within Other Property and Investments of $10 million ($2 million PSO, $3 million SWEPCo and $5 million TCC) and the subordinated debentures are now reported as Notes Payable to Trust within Long-term Debt of $331 million ($77 million PSO, $113 million SWEPCo and $141 million TCC).

The Junior Subordinated Debentures of PSO and TCC mature on April 30, 2037. In October 2003, SWEPCo refinanced its Junior Subordinated Debentures which are now due October 1, 2043. The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2003 and 2002:

Business Trust	Security	Units Issued/ Outstanding at 12/31/03	Amount in Other Investments at 12/31/03 (a) (in millions)	Amount in Notes Payable to Trust at 12/31/03 (b) (in millions)	Amount Reported Prior to FIN 46 at 12/31/02 (c) (in millions)	Description of Underlying Debentures of Registrant
CPL Capital I	8.00%, Series A	5,450,000	$5	$141	$136	TCC, $141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	2	77	75	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	7.875%, Series A	-	-	-	110	SWEPCo, $113 million, 7.875%, Series A
SWEPCo Capital I	5.25%, Series B	110,000	3	113	-	SWEPCo, $113 million, 5.25% five year fixed rate period, Series B
		8,560,000	$10	$331	$321	

(a) Amounts are in Other Investments within Other Property and Investments.
(b) Amounts are in Notes Payable to Trust within Long-term Debt.
(c) Amounts reported on Balance Sheet prior to FIN 46.

Each of the business trusts is treated as a non-consolidated 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.

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a utility money pool, which funds the utility subsidiaries, and a non-utility money pool, which funds the majority of the non-utility subsidiaries. In addition, the AEP System also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. The AEP System Corporate Borrowing Program operates in accordance with the terms and conditions outlined by the SEC. AEP has authority from the SEC through March 31, 2006 for short-term borrowings sufficient to fund the utility money pool and the non-utility money pool as well as its own requirements in an amount not to exceed $7.2 billion. Utility money pool participants include AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC (domestic utility companies). The following are the SEC-authorized limits for short-term borrowings for the domestic utility companies as of December 31, 2003:

	Authorized (in millions)
AEP Generating Company	$125
AEP Texas Central Company (a)	438
AEP Texas North Company (a)	275
Appalachian Power Company	600
Columbus Southern Power Company (a)	150
Indiana Michigan Power Company	500
Kentucky Power Company	200
Ohio Power Company (a)	200
Public Service Company of Oklahoma	300
Southwestern Electric Power Company	350

(a) Short-term borrowing limits for these domestic utility companies are reduced by long-term debt issued commencing with the SEC order dated December 18, 2002, which authorized financing transactions through March 31, 2006.

As of December 31, 2003, AEP had credit facilities totaling $2.9 billion to support its commercial paper program. At December 31, 2003, AEP had $326 million outstanding in short-term borrowings of which $282 million was commercial paper supported by the revolving credit facilities. In addition, JMG has commercial paper outstanding in the amount of $26 million. This commercial paper is specifically associated with the Gavin scrubber lease identified in Note 15 "Leases". This commercial paper does not reduce available liquidity to AEP. The maximum amount of commercial paper outstanding during the year, which had a weighted average interest rate during 2003 of 1.98%, was $1.5 billion during January 2003. On December 11, 2002, Moody's Investor Services placed AEP's Prime-2 short-term rating for commercial paper under review for possible downgrade. On January 24, 2003, Standard & Poor's Rating Services placed AEP's A-2 short-term rating for commercial paper under review for possible downgrade. On February 10, 2003, Moody's Investor Services downgraded AEP's short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poor's Rating Services reaffirmed AEP's A-2 short-term rating for commercial paper.

Net interest income (expense) recorded by each registrant subsidiary related to amounts advanced to (borrowed from) the AEP money pool were:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
AEGCo	$(0.3)	$(0.2)	$(0.7)
APCo	1.4	(4.1)	(9.9)
CSPCo	-	(1.1)	(4.9)
I&M	1.5	1.0	(12.6)
KPCo	(0.9)	(1.6)	(2.3)
OPCo	(1.6)	(5.7)	(13.2)
PSO	(1.1)	(4.1)	(5.8)
SWEPCo	0.1	(2.8)	(2.3)
TCC	-	(6.3)	(11.1)
TNC	(0.3)	(3.2)	(3.0)

Outstanding short-term debt for AEP Consolidated consisted of:

	Year Ended December 31,	
	2003	2002
	(in millions)	
Balance Outstanding:		
Notes Payable	$18	$1,322
Commercial Paper – AEP	282	1,417
Commercial Paper – JMG	26	-
Total	$326	$2,739

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. We continue to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain registrant subsidiaries and, until the first quarter of 2002, with non-affiliated companies. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. As a result of the restructuring of electric utilities in the State of Texas, the purchase agreement between AEP Credit and Reliant Energy, Incorporated was terminated as of January 25, 2002 and the purchase agreement between AEP Credit and Texas-New Mexico Power Company, the last remaining non-affiliated company, was terminated on February 7, 2002. In addition, the purchase agreements between AEP Credit and its Texas affiliates, AEP Texas Central Company (formerly Central Power and Light Company) and AEP Texas North Company (formerly West Texas Utilities Company) were terminated effective March 20, 2002.

Comparative accounts receivable information for AEP Credit:

	Year Ended December 31,	
	2003	2002
	(in millions)	
Proceeds from Sale of Accounts Receivable	$5,221	$5,513
Accounts Receivable Retained Interest Less Uncollectible Accounts and Amounts Pledged as Collateral	124	76
Deferred Revenue from Servicing Accounts Receivable	1	1
Loss on Sale of Accounts Receivable	7	4
Average Variable Discount Rate	1.33%	1.92%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	122	74
Retained Interest if 20% Adverse Change in Uncollectible Accounts	121	72

Historical loss and delinquency amount for the AEP System's customer accounts receivable managed portfolio:

	Face Value Year Ended December 31,	
	2003	2002
	(in millions)	
Customer Accounts Receivable Retained	$1,155	$1,553
Accrued Unbilled Revenues Retained	596	551
Miscellaneous Accounts Receivable Retained	83	93
Allowance for Uncollectible Accounts Retained	(124)	(108)
Total Net Balance Sheet Accounts Receivable	1,710	2,089
Customer Accounts Receivable Securitized (Affiliate)	385	454
Total Accounts Receivable Managed	$2,095	$2,543
Net Uncollectible Accounts Written Off	$39	$48

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

At December 31, 2003, delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors was $30 million.

Under the factoring arrangement, participating registrant subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company's receivables and administrative costs. The costs of factoring customer accounts receivable are reported as an operating expense. The amount of factored accounts receivable and accrued unbilled revenues for each registrant subsidiary was as follows:

	December 31,	
	2003	2002
	(in millions)	
APCo	$60.2	$67.6
CSPCo	100.2	114.3
I&M	93.0	103.7
KPCo	30.4	29.5
OPCo	99.3	109.8
PSO	99.6	83.7
SWEPCo	64.4	65.2

The fees paid by the registrant subsidiaries to AEP Credit for factoring customer accounts receivable were:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
APCo	$3.4	$ 4.8	$ 5.2
CSPCo	9.8	15.8	15.2
I&M	6.1	7.4	8.5
KPCo	2.4	2.7	2.7
OPCo	8.7	11.4	12.8
PSO	5.8	7.2	9.6
SWEPCo	4.9	5.4	7.4
TCC	-	2.2	14.7
TNC	-	1.4	3.8

17. RELATED PARTY TRANSACTIONS

AEP System Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO2 Allowances associated with transactions under the Interconnection Agreement. As part of AEP's restructuring settlement agreement filed with FERC, under certain conditions CSPCo and OPCo would no longer be parties to the Interconnection Agreement and certain other modifications to its terms would also be made.

Power and Gas and risk management activities are conducted by the AEP Power Pool and shared among the parties under the System Integration Agreement. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices and the risk management of electricity and to a lesser extent gas contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

AEP West Companies

PSO, SWEPCo, TCC, TNC operating companies of the west zone and AEPSC 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 AEP West operating companies to maintain specified annual planning reserve margins and requires the operating companies that have capacity in excess of the required margins to make such capacity available for sale to other operating companies as capacity commitments. The CSW Operating Agreement also delegates to AEPSC 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. As part of AEP's restructuring settlement agreement filed with the FERC, under certain conditions TCC and TNC would no longer be parties to the CSW Operating Agreement.

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.

The following table shows the revenues derived from sales to the pools and direct sales to affiliates for years ended December 31, 2003, 2002 and 2001:

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
			(in thousands)			
2003 Sales to East System Pool	$130,921	$59,113	$228,667	$32,827	$503,334	$-
Sales to West System Pool	27	9	17	6	21	-
Direct Sales To East Affiliates	60,638	-	-	-	50,764	232,955
Direct Sales To West Affiliates	27,951	16,428	17,674	6,425	21,759	-
Other	3,256	8,819	2,845	550	8,400	-
Total Revenues	$222,793	$84,369	$249,203	$39,808	$584,278	$232,955
2002 Sales to East System Pool	$106,651	$42,986	$197,525	$22,369	$397,248	$-
Sales to West System Pool	18,300	12,107	13,036	4,717	16,265	-
Direct Sales To East Affiliates	58,213	-	-	-	50,599	213,071
Direct Sales To West Affiliates	-	-	-	-	-	-
Other	3,313	2,109	3,577	878	1,090	-
Total Revenues	$186,477	$57,202	$214,138	$27,964	$465,202	$213,071
2001 Sales to East System Pool	$91,977	$44,185	$239,277	$34,735	$431,637	$-
Sales to West System Pool	24,892	13,971	15,596	6,117	19,797	-
Direct Sales To East Affiliates	54,777	-	-	-	55,450	227,338
Direct Sales To West Affiliates	(3,133)	(1,705)	(1,905)	(744)	(2,590)	-
Other	2,772	11,060	2,071	2,258	7,072	-
Total Revenues	$171,285	$67,511	$255,039	$42,366	$511,366	$227,338

Related Party Revenues	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2003 Sales to East System Pool	$-	$-	$-	$-
Sales to West System Pool	793	600	15,157	651
Direct Sales To East Affiliates	1,159	706	677	6
Direct Sales To West Affiliates	17,855	64,802	23,248	1,929
Other	3,323	2,746	114,486	52,567
Total Revenues	$23,130	$68,854	$153,568	$55,153
2002 Sales to East System Pool	$-	$-	$-	$-
Sales to West System Pool	674	1,334	18,416	1,280
Direct Sales To East Affiliates	611	270	366	(23)
Direct Sales To West Affiliates	6,047	75,674	956,751	228,404
Other	2,107	(4,979)	32,911	10,764
Total Revenues	$9,439	$72,299	$1,008,444	$240,425
2001 Sales to East System Pool	$4	$-	$-	$-
Sales to West System Pool	3,317	8,073	19,865	322
Direct Sales To East Affiliates	2,833	3,238	3,697	1,228
Direct Sales To West Affiliates	30,668	67,930	12,617	9,350
Other	(51)	(4)	5,583	7,781
Total Revenues	$36,771	$79,237	$41,762	$18,681

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2003, 2002, and 2001:

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2003 Purchases from East System Pool	$348,899	$335,916	$109,826	$71,259	$88,962
Purchases from West System Pool	-	-	-	-	-
Direct Purchases from East Affiliates	1,546	936	164,069	70,249	1,234
Direct Purchases from West Affiliates	765	471	505	182	625
Total Purchases	$351,210	$337,323	$274,400	$141,690	$90,821
2002 Purchases from East System Pool	$233,677	$309,999	$83,918	$68,846	$70,338
Purchases from West System Pool	337	219	237	86	297
Direct Purchases from East Affiliates	583	387	149,569	64,070	519
Direct Purchases from West Affiliates	-	-	-	-	-
Total Purchases	$234,597	$310,605	$233,724	$133,002	$71,154
2001 Purchases from East System Pool	$346,582	$292,034	$79,030	$61,816	$62,350
Purchases from West System Pool	296	165	185	72	235
Direct Purchases from East Affiliates	-	-	159,022	68,316	-
Direct Purchases from West Affiliates	-	-	-	-	-
Total Purchases	$346,878	$292,199	$238,237	$130,204	$62,585

Related Party Purchases		PSO	SWEPCo	TCC	TNC
			(in thousands)		
2003	Purchases from East System Pool	$639	$-	$-	$-
	Purchases from West System Pool	704	741	289	15,467
	Direct Purchases from East Affiliates	46,384	28,376	10,238	4,677
	Direct Purchases from West Affiliates	61,912	18,087	8,570	19,265
	Other	-	710	-	-
	Total Purchases	$109,639	$47,914	$19,097	$39,409
2002	Purchases from East System Pool	$343	$-	$-	$-
	Purchases from West System Pool	874	(456)	1,366	15,475
	Direct Purchases from East Affiliates	29,029	17,242	8,236	2,669
	Direct Purchases from West Affiliates	59,208	25,236	13,804	19,438
	Total Purchases	$89,454	$42,022	$23,406	$37,582
2001	Purchases from East System Pool	$1,327	$-	$-	$4
	Purchases from West System Pool	5,877	3,810	415	11,689
	Direct Purchases from East Affiliates	1,951	2,352	12,657	4,614
	Direct Purchases from West Affiliates	34,603	9,696	45,569	40,349
	Total Purchases	$43,758	$15,858	$58,641	$56,656

The above summarized related party revenues and expenses are reported in their entirety, without elimination, and are presented as operating revenues affiliated and purchased power affiliated on the statements of operations of each AEP Power Pool member. Since all of the above pool members are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

AEP System Transmission Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

The following table shows the net (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
		(in thousands)	
APCo	$-	$(13,400)	$(3,100)
CSPCo	38,200	42,200	40,200
I&M	(39,800)	(36,100)	(41,300)
KPCo	(5,600)	(5,400)	(4,600)
OPCo	7,200	12,700	8,800

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA established 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 AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the west zone operating subsidiaries of revenues collected for transmission and ancillary services provided under the OATT.

The following table shows the net (credits) or charges allocated among parties to the Transmission Agreement during the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
		(in thousands)	
PSO	$4,200	$4,200	$4,000
SWEPCo	5,000	5,000	5,400
TCC	(3,600)	(3,600)	(3,900)
TNC	(5,600)	(5,600)	(5,500)

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.

AEP Coal, Inc.

AEP Coal, Inc. and CSPCo are parties to a 2003 coal purchase agreement, dated October 15, 2002. The agreement provides for the sale of up to 960,000 tons of coal mined by AEP Coal to be delivered (at CSP's expense) to the Conesville Plant for a price ranging from $23.15 per ton to $26.15 per ton plus quality adjustments. In 2002, AEP Coal, Inc. and CSPCo were parties to a 2002 coal purchase agreement, dated February 1, 2002. The agreement provided for the sale of up to 785,000 tons of coal mined by AEP Coal to be delivered (at CSP's expense) to the Conesville Plant for a price ranging from $24.00 per ton to $27.00 per ton plus quality adjustments. During 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of $23.9 million and $21 million, respectively.

AEP Coal, Inc. and CSPCo are parties to a 1998 coal transloading agreement, dated June 12, 1998. Pursuant to the agreement, AEP Coal transfers coal from railcars into trucks at AEP Coal's Muskie Transloading Facility and delivers the coal via trucks to CSPCo's Conesville Preparation Plant or CSPCo's Power Plant for a rate of $1.25 per ton and $1.03 per ton, respectively. During 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of $3.4 million and $3.5 million, respectively.

AEP East Companies

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East operating companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Concurrently, in order to ensure that there would be no financial impact to the operating companies as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. There is no impact to the AEP consolidated financial statements. The following table represents registrant subsidiary liabilities at December 31, 2003 in thousands:

APCo	$(32,287)
CSPCo	(18,185)
I&M	(19,932)
KPCo	(7,349)
OPCo	(24,055)
Total	$(101,808)

Unit Power Agreements and Other

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) 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. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement expires on December 31, 2004.

APCo and OPCo, jointly own two power plants. The costs of operating these facilities are apportioned between the owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on each company's consolidated statements of income. Each company's investment in these plants is included in electric utility plant on its consolidated balance sheets.

I&M provides barging and other transportation services to affiliates. I&M records revenues from barging services as nonoperating income. The affiliates record costs paid to I&M for barging services as fuel expense or operation expense. The amount of affiliated revenues and affiliated expenses were:

	Year Ended December 31,		
	2003	**2002**	**2001**
Company		**(in millions)**	
I&M – revenues	$31.9	$34.3	$30.2
AEGCo – expense	8.1	7.8	8.5
APCo – expense	12.3	12.8	11.5
KEPCo – expense	0.1	-	-
OPCo – expense	4.3	7.9	10.2
MEMCo – expense (Non-Utility subsidiary of AEP)	7.1	5.7	-
AEP Energy Services (Non-Utility subsidiary of AEP)	-	0.1	-

In conjunction with a 500 MW agreement between OPCo and National Power Cooperative, Inc (NPC), AEPES entered into a fuel management agreement with those two parties to manage and procure fuel needs for the plant, which is owned by NPC. The plant went into service in July 2002. Because APCo, CSPCo, I&M, KPCo and OPCo purchase 100% of the available generating capacity from the plant, they also share in paying fuel expense to AEPES. The related purchases from AEPES were as follows:

	Year Ended December 31,	
	2003	2002
	(in thousands)	
KPCo	$363	$150
I&M	1,000	418
CSPCo	936	387
OPCo	1,234	519
APCo	1,546	583
Total	$5,079	$2,057

There was no activity in 2001.

HPL purchases physical gas in the spot market, which in turn, is sold to certain operating companies at cost for their fuel requirements. The related sales are as follows:

	Year Ended December 31,	
	2003	2002
	(in thousands)	
TCC	$195,527	$157,346
TNC	44,197	64,385

There was no activity in 2001.

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for shared services. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP Co., Inc. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the PUHCA.

18. JOINTLY OWNED ELECTRIC UTILITY PLANT

CSPCo, PSO, SWEPCo, TCC and TNC have generating units that are jointly owned with affiliated and unaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly owned facilities in the same proportion as its ownership interest. Each AEP registrant subsidiary's proportionate share of the operating costs associated with such facilities is included in its statements of operations and the investments are reflected in its balance sheets under utility plant as follows:

		Company's Share			
		December 31,			
		2003		2002	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
		(in thousands)		(in thousands)	
CSPCo					
W.C. Beckjord Generating Station (Unit No. 6)	12.5	$15,455	$127	$15,487	$49
Conesville Generating Station (Unit No. 4)	43.5	82,115	722	81,960	279
J.M. Stuart Generating Station	26.0	204,820	50,326	197,276	44,865
Wm. H. Zimmer Generating Station	25.4	707,281	31,249	705,620	14,077
Transmission	(a)	62,061	742	61,187	2,281
Total		$1,071,732	$83,166	$1,061,530	$61,551
PSO					
Oklaunion Generating Station (Unit No. 1)	15.6	$85,064	$518	$83,562	$777
SWEPCo					
Dolet Hills Generating Station (Unit No. 1)	40.2	$236,116	$2,304	$235,366	$1,313
Flint Creek Generating Station (Unit No. 1)	50.0	93,309	737	91,567	1,052
Pirkey Generating Station (Unit No. 1)	85.9	454,303	3,125	451,136	2,197
Total		$783,728	$6,166	$778,069	$4,562
TCC (b)					
Oklaunion Generating Station (Unit No. 1)	7.8	$38,798	$252	$38,055	$369
South Texas Project Generation Station (Units No. 1 and 2)	25.2	2,386,579	934	2,364,359	43,887
Total		$2,425,377	$1,186	$2,402,414	$44,256
TNC					
Oklaunion Generating Station (Unit No. 1)	54.7	$285,314	$1,351	$277,946	$3,650

(a) Varying percentages of ownership.
(b) Included in Assets Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

The accumulated depreciation with respect to each AEP registrant subsidiary's share of jointly owned facilities is shown below:

	December 31, 2003	December 31, 2002
	(in thousands)	
CSPCo	$435,249	$436,683
PSO	50,968	49,085
SWEPCo	465,871	450,057
TCC (a)	991,665	927,193
TNC	103,642	102,542

(a) Included in Assets Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

The unaudited quarterly financial information for each AEP registrant subsidiary follows:

Quarterly Periods Ended	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
March 31, 2003					
Operating Revenues	$60,428	$536,228	$359,205	$418,598	$112,094
Operating Income	1,851	112,684	55,151	58,990	19,834
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,796	79,153	38,359	30,687	11,021
Net Income	1,796	156,410	65,642	27,527	9,887
June 30, 2003					
Operating Revenues	$59,568	$444,751	$333,071	$376,906	$95,464
Operating Income	1,514	49,056	43,417	19,229	10,964
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,768	14,636	29,331	(1,191)	4,095
Net Income (Loss)	1,768	14,636	29,331	(1,191)	4,095
September 30, 2003					
Operating Revenues	$59,008	$483,611	$397,655	$423,004	$103,693
Operating Income	1,809	67,134	71,193	56,242	13,097
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	2,021	45,715	62,825	37,116	6,501
Net Income	2,021	45,715	62,825	37,116	6,501
December 31, 2003					
Operating Revenues	$54,161	$492,768	$341,920	$377,088	$105,219
Operating Income	2,000	89,937	55,725	51,606	20,849
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	2,379	63,279	42,632	22,936	11,847
Net Income	2,379	63,279	42,632	22,936	11,847

Quarterly Periods Ended	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
March 31, 2003					
Operating Revenues	$590,631	$242,662	$255,278	$428,358	$116,262
Operating Income	98,870	13,146	26,044	92,010	9,865
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	68,350	691	10,491	64,437	6,765
Net Income	192,982	691	19,008	64,559	9,836
June 30, 2003					
Operating Revenues	$539,386	$277,236	$281,306	$482,446	$136,806
Operating Income	79,831	28,715	35,588	96,603	23,243
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	56,277	17,927	20,590	63,587	17,922
Net Income	56,277	17,927	20,590	63,587	17,922
September 30, 2003					
Operating Revenues	$565,318	$358,575	$361,622	$485,129	$114,455
Operating Income	93,798	43,527	59,229	84,502	17,419
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	70,367	38,090	42,181	66,221	17,347
Net Income	70,367	38,090	42,181	66,221	17,347
December 31, 2003					
Operating Revenues	$549,318	$224,349	$248,636	$351,578	$98,423
Operating Income	87,168	7,475	29,275	48,425	17,500
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	56,037	(2,817)	16,362	23,302	13,629
Net Income (Loss)	56,037	(2,817)	16,362	23,302	13,452

Quarterly Periods Ended	AEGCo	APCo	CSPCo	I&M	KPCo
		(in thousands)			
March 31, 2002					
Operating Revenues	$49,875	$462,605	$314,826	$352,235	$99,185
Operating Income	1,767	81,554	45,548	30,363	15,484
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,893	55,341	33,858	11,058	10,246
Net Income	1,893	55,341	33,858	11,058	10,246
June 30, 2002					
Operating Revenues	$53,356	$432,015	$343,813	$369,043	$92,164
Operating Income	1,504	65,224	58,040	19,865	9,550
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,718	46,608	51,721	7,494	5,246
Net Income	1,718	46,608	51,721	7,494	5,246
September 30, 2002					
Operating Revenues	$55,988	$464,409	$421,892	$414,414	$97,811
Operating Income	1,436	81,365	89,033	57,004	11,119
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,947	53,947	76,117	35,312	5,994
Net Income	1,947	53,947	76,117	35,312	5,994
December 31, 2002					
Operating Revenues	$54,062	$455,441	$319,629	$391,072	$89,523
Operating Income	1,422	73,920	27,158	43,957	6,044
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,994	49,596	19,477	20,128	(919)
Net Income (Loss)	1,994	49,596	19,477	20,128	(919)

Quarterly Periods Ended	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
March 31, 2002					
Operating Revenues	$520,652	$148,986	$222,259	$278,910	$103,626
Operating Income	83,716	8,410	22,469	55,445	11,145
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	64,051	(1,648)	8,159	24,445	3,992
Net Income (Loss)	64,051	(1,648)	8,159	24,445	3,992
June 30, 2002					
Operating Revenues	$521,365	$158,330	$263,074	$360,391	$104,452
Operating Income	61,046	20,201	31,988	64,319	5,547
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	55,348	11,620	18,155	33,535	675
Net Income	55,348	11,620	18,155	33,535	675
September 30, 2002					
Operating Revenues	$557,574	$230,098	$362,423	$546,260	$152,667
Operating Income (Loss)	97,210	50,710	60,254	118,204	(308)
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	80,258	41,002	45,794	93,383	(4,193)
Net Income (Loss)	80,258	41,002	45,794	93,383	(4,193)
December 31, 2002					
Operating Revenues	$513,534	$256,233	$236,964	$504,932	$89,995
Operating Income (Loss)	56,357	5,400	27,758	155,765	(8,513)
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	20,366	(9,914)	10,884	124,578	(14,151)
Net Income (Loss)	20,366	(9,914)	10,884	124,578	(14,151)

For each of the AEP registrant subsidiaries, there were no significant, non-recurring events in the fourth quarter of 2003 or 2002.

20. SUBSEQUENT EVENTS (UNAUDITED)

After December 31, 2003 we entered into separate agreements to dispose of the following investments:

Investment	Sales Price (in millions)	Date of Agreement
Oklaunion Power Station (TCC's 7.8% ownership interest)	$42.8	January 30, 2004
STP (TCC's 25.2% ownership interest)	$332.6	February 27, 2004

We anticipate these sales to be completed during 2004 and that the impact on results of operations will not be significant.

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REGISTRANTS' COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, (iii) footnotes and (iv) the schedules of each individual registrant.

Source of Funding

Short-term funding for AEP's electric subsidiaries comes from AEP's commercial paper program and revolving credit facilities. Proceeds are loaned to the subsidiaries through intercompany notes. AEP and its subsidiaries also operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity for certain electric subsidiaries. The electric subsidiaries generally use short-term funding sources (the money pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leaseback, leasing arrangements and additional capital contributions from their parent company.

Sale of Receivables Through AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be removed from of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. The electric subsidiaries continue to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain registrant subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. In addition, the purchase agreements between AEP Credit and TCC and TNC were terminated effective March 20, 2002.

Budgeted Construction Expenditures

Construction expenditures for certain registrant subsidiaries for the next three years are:

	Projected Construction Expenditures (in millions)	Construction Expenditures Financed With Internal Funds
APCo	$1,307	70%
I&M	645	100
OPCo	1,686	60
SWEPCo	414	100
TCC	531	100

Significant Factors

Possible Divestitures

AEP's management is firmly committed to continually evaluating the need to reallocate resources to areas that effectively match investments with our business strategy, providing the greatest potential for financial returns and to disposing of investments that no longer meet these goals.

TCC is seeking to divest significant components of its non-regulated domestic generation assets. In June 2003, TCC began actively seeking buyers for 4,497 megawatts of its generating capacity in Texas. The value received from this disposition will also be used to calculate stranded costs in Texas (see Note 6). Management is currently evaluating bids received during the fourth quarter of 2003 and is in negotiations to sell these assets. See Note 10 for discussion of impairments recorded related to the generating units in Texas. The ultimate sale of these assets may have a material impact on results of operations, cash flows and financial condition if losses are not recovered through the 2004 true-up proceeding in Texas.

Management continues to have periodic discussions with various parties on business alternatives for certain other investments. The ultimate timing for a disposition of one or more of these assets will depend upon market conditions and the value of any buyer's proposal.

Corporate Separation

In compliance with certain provisions in the Texas and Ohio restructuring laws, AEP filed in 2001 for regulatory approvals related to efforts at that time to separate regulated and unregulated operations, and amend certain affiliate pooling arrangements. Although certain regulatory approvals have been obtained, with the changes in the regulatory environment and AEP's business strategy, management continues to evaluate corporate separation plans.

In Texas, TCC is in the process of divesting its generating assets in accordance with provisions of the Texas Legislation concerning stranded cost recovery (see Note 6). In order to sell these assets, TCC anticipates retiring first mortgage bonds by making open market purchases or defeasing the bonds. Once such generating assets are sold, which management expect to be finalized in 2004, TCC will effectively accomplish the structural separation requirements of the Texas Legislation for those assets.

In Ohio, the PUCO has encouraged utilities to file rate stabilization plans to provide rate certainty and stability for customers who do not choose alternative suppliers, for the period of January 1, 2006 through December 31, 2008, which is after the expiration of the current market development period. On February 9, 2004, CSPCo and OPCo filed such a rate stabilization plan with the PUCO. The plan, in part, provides that both CSPCo and OPCo will remain functionally separated. Approval of the rate stabilization plan is currently pending before the PUCO.

Unless otherwise directed by the PUCO in an order on the rate stabilization plan, CSPCo and OPCo will remain functionally separated through at least the end of the rate stabilization plan period, December 31, 2008, and therefore, are not planning to legally separate, or to change the affiliate pooling agreement for the AEP East companies, in the foreseeable future.

Management continues to evaluate the most appropriate approach for complying with the Texas Legislation's structural separation requirements for TNC, including appropriate regulatory approvals to implement its structural separation.

RTO Formation

The FERC's AEP-CSW merger approval and many of the settlement agreements with the state regulatory commissions to approve the AEP-CSW merger required the transfer of functional control of our subsidiaries' transmission systems to RTOs. Further, legislation in some of AEP's states requires RTO participation.

In May 2002, AEP announced an agreement with PJM to pursue terms for participation in its RTO for AEP East companies with final agreements to be negotiated. In July 2002, FERC issued an order accepting our decision to participate in PJM, subject to specified conditions. AEP and other parties continue to work on the resolution of those conditions.

In December 2002, AEP's subsidiaries that operate in the states of Indiana, Kentucky, Ohio and Virginia filed for state regulatory commission approval of their plans to transfer functional control of their transmission assets to PJM. Proceedings in Ohio remain pending.

In February 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed a cost/benefit study with the Virginia SCC covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately $13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In April 2003, FERC approved our transfer of functional control of the AEP East companies' transmission system to PJM. FERC also accepted our proposed rates for joining PJM, but set a number of rate issues for resolution through settlement proceedings or FERC hearings. Settlement discussions continue on certain rate matters.

On September 29 and 30, 2003, the FERC held a public inquiry regarding RTO formation, including delays in AEP's participation in PJM. In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger commitment to join an RTO by fully integrating into PJM (transmission and markets) by October 1, 2004. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the states' provisions meet either of the two exceptions under PURPA. The FERC directed the ALJ to issue his initial decision by March 15, 2004.

If AEP East companies do not obtain regulatory approval to join PJM, they are committed to reimburse PJM for certain project implementation costs (presently estimated at $24 million for AEP's share of the entire PJM integration project). These costs, if incurred, will be allocated to the AEP East companies. AEP East companies also plan to seek recovery of deferred RTO formation/integration costs in the future. At December 31, 2003, the deferred amounts per company are as follows:

Company	(in millions)
APCo	$7.8
CSPCo	3.3
I&M	6.0
KPCo	1.8
OPCo	8.6

See Note 4 for further discussion.

AEP West companies are members of ERCOT or SPP. In 2002, FERC conditionally accepted filings related to a proposed consolidation of MISO and SPP. State public utility commissions also regulate AEP's SPP companies. The Louisiana and Arkansas commissions filed responses to the FERC's RTO order indicating that additional analysis was required. Subsequently, the proposed SPP/MISO combination was terminated. On October 15, 2003, SPP filed a proposal at the FERC for recognition as an RTO. In February 2004, the FERC granted RTO status to the SPP, subject to fulfilling specified requirements. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

Management is unable to predict the outcome of these regulatory actions and proceedings or their impact on transmission operations, results of operations and cash flows or the timing and operation of RTOs.

Pension Plans

AEP maintains qualified defined benefit pension plans (Qualified Plans), which cover a substantial majority of non-union and certain union associates, and unfunded excess plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, AEP has entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits.

AEP's net periodic pension expense was an income item for all pension plans approximating $3 million and $44 million for the years ended December 31, 2003 and 2002, respectively, and is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Qualified Plans' assets. In 2002 and 2003, the long-term return was assumed to be 9.00%, and for 2004, the long-term rate of return was lowered to 8.75%. In developing the expected long-term rate of return assumption, AEP evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. AEP also considered historical returns of the investment markets as well as the 10-year average return, for the period ended December 2003, of approximately 10.0%. AEP anticipates that the investment managers it employs for the pension fund will continue to generate long-term returns of at least 8.75%.

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

	2003 Actual Asset Allocation	2004 Target Asset Allocation	Assumed/Expected Long-term Rate of Return
		(in percentage)	
Equity	71	70	10.5
Fixed Income	27	28	5
Cash and Cash Equivalents	2	2	2
Total	100	100	
Overall Expected Return (weighted average)			8.75

AEP regularly reviews the actual asset allocation and periodically rebalances the investments to its targeted allocation when considered appropriate. AEP believes that 8.75% is a reasonable long-term rate of return on the Qualified Plans' assets despite the recent market volatility in which the Qualified Plans' assets had a loss of 11.2% for the twelve months ended December 31, 2002, and a gain of 23.8% for the twelve months ended December 31, 2003. AEP will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them as necessary.

AEP bases its determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2003, AEP has cumulative losses of approximately $325 million which remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The discount rate that AEP utilizes for determining future pension obligations is based on a review of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis has decreased from 6.75% at December 31, 2002, to 6.25% at December 31, 2003. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Qualified Plans' assets of 8.75%, a discount rate of 6.25% and various other assumptions, AEP estimates that the pension expense for all pension plans will approximate $41 million, $78 million and $103 million in 2004, 2005 and 2006, respectively. Future actual pension cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the pension plans.

Lowering the expected long-term rate of return on the Qualified Plans' assets by 0.5% (from 9.0% to 8.5%) would have increased pension cost for 2003 by approximately $18 million (income of $3 million would have become $15 million in pension expense). Lowering the discount rate by 0.5% would have reduced pension income for 2003 by approximately $0.5 million.

The value of the Qualified Plans' assets has increased from $2.795 billion at December 31, 2002 to $3.180 billion at December 31, 2003. The Qualified Plans paid out $292 million in benefits to plan participants during 2003 (the nonqualified plans paid out $7 million in benefits). AEP's pension plans remain in an underfunded position (plan assets are less than projected benefit obligations) of $508 million at December 31, 2003. Due to the pension plans currently being underfunded, AEP recorded a charge to Other Comprehensive Income (OCI) of $585 million in 2002, and recorded a Deferred Income Tax Asset of $315 million, offset by a Minimum Pension Liability of $662 million and a reduction to prepaid costs and adjustment for unrecognized costs of $238 million. In 2003, the income recorded in OCI was $154 million, and the reduction in the Deferred Income Tax Asset was $76 million, offset by a reduction in Minimum Pension Liability of $234 million and a reduction to adjustment for unrecognized costs of $4 million. The charge to OCI does not affect earnings or cash flow. AEP's plans are in compliance with the laws and regulations governing such plans including the Employee Retirement Income Security Act of 1974, as amended. Due to the current underfunded status of the Qualified Plans, AEP expects to make cash contributions to the pension plans of approximately $41 million in 2004.

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

See Note 11 of the Notes to Respective Financial Statements for additional information related to the impact of pension plans on individual AEP registrant subsidiaries.

Nuclear Plant Outages

In April 2003, engineers at STP, during inspections conducted regularly as part of refueling outages, found wall cracks in two bottom mounted instrument guide tubes of STP Unit 1. These tubes were repaired and the unit returned to service in August 2003. TCC's share of the cost of repair for this outage was approximately $6 million. TCC had commitments to provide power to customers during the outage. Therefore, TCC was subject to fluctuations in the market prices of electricity and purchased replacement energy.

In April 2003, both units of Cook Plant were taken offline due to an influx of fish in the plant's cooling water system which caused a reduction in cooling water to essential plant equipment. After repair of damage caused by the fish intrusion, Cook Plant Unit 1 returned to service in May and Unit 2 returned to service in June following completion of a scheduled refueling outage.

Litigation

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation under "Environmental Matters".

Enron Bankruptcy

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. AEP will assert its right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

During 2002 and 2001, AEP subsidiaries expensed a total of $53 million ($34 million net of tax) for their estimated loss from the Enron bankruptcy. The amounts for certain subsidiaries were:

Registrant	Amounts Expensed	Amounts Net of Tax
	(in millions)	
APCo	$5.3	$3.4
CSPCo	2.7	1.8
I&M	2.8	1.8
KPCo	1.1	0.7
OPCo	3.6	2.3

The amounts expensed were based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Energy Market Investigations

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

In March 2003, AEP received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, AEP received an informal data request from the SEC seeking that AEP voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. AEP responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, AEP recorded a provision in 2003 and the action is not expected to have a material effect on results of operations.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. AEP is responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

TEM Litigation

See discussion of TEM litigation within OPCo's Management's Financial Discussion and Analysis.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit against AEP and four of its subsidiaries including TCC and TNC, certain unaffiliated energy companies and ERCOT alleging violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Management believes that the claims against AEP and its subsidiaries are without merit. Management intends to vigorously defend against the claims. See Note 7 for further discussion.

COLI Litigation

A decision by the U.S. District Court for the Southern District of Ohio in February 2001 that denied AEP's deduction of interest claimed on AEP's consolidated federal income tax returns related to a COLI program resulted in a $319 million reduction in AEP's Net Income for 2000.

The earnings reductions for affected registrant subsidiaries were as follows:

	(in millions)
APCo	$82
CSPCo	41
I&M	66
KPCo	8
OPCo	118

AEP filed an appeal of the U.S. District Court's decision with the U.S. Court of Appeals for the 6th Circuit. In April 2003, the Appeals Court ruled against AEP. The U.S. Supreme Court has declined to hear this issue.

Other Litigation

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

Potential Uninsured Losses

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

Environmental Matters

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

- Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,

- New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
- Possible future requirements to reduce carbon dioxide emissions to address concerns about global climatic change.

In addition to achieving full compliance with all applicable legal requirements, AEP subsidiaries strive to go beyond compliance in an effort to be good environmental stewards. For example, AEP subsidiaries invest in research, through groups like the Electric Power Research Institute, to develop, implement and demonstrate new emission control technologies. AEP subsidiaries plan to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices. AEP subsidiaries have a proven record of efficiently producing and delivering electricity while minimizing the impact on the environment. The AEP System has invested over $2 billion, from 1990 through 2003, to equip many of its facilities with pollution control technologies. The AEP System will continue to make investments to improve the air emissions from its generating stations because this is the most cost-effective generation source for its customers electricity needs.

The Current Air Quality Regulatory Framework

The Clean Air Act (CAA) is the legislation that establishes the federal regulatory authority and oversight for emissions from fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

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

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

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

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

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which we operate that were subject to the NOx Rule have submitted the required SIP revisions. In response, the Federal EPA issued the NOx Rule and the Section 126 Rule, which are discussed below.

The compliance date for the NOx Rule is May 31, 2004. In 2000, the Federal EPA also adopted a revised Section 126 Rule which granted petitions filed by four northeastern states. The revised Section 126 Rule imposes emissions reduction requirements comparable to the NOx Rule also beginning May 31, 2004, for most of our coal-fired generating units.

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

AEP subsidiaries are installing a variety of emission control technologies to improve NOx emissions standards and to comply with applicable state and federal NOx requirements. These include selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units.

AEP's electric utility units are currently subject to SIP requirements that control SO_2 and particulate matter emissions in all states, and that control NOx emissions in certain states. The AEP System's generating plants comply with applicable SIP limits for SO_2, NOx and particulate matter.

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

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

Different NSR requirements apply in attainment and non-attainment areas.

In attainment areas:

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

In non-attainment areas,

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

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

Title IV of the CAA (Acid Rain)

The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO_2 emitted from electric utility units by approximately 50 percent from 1980 levels. This program also established a nationwide cap on utility SO_2 emissions of 8.9 million tons per year. The Federal EPA administers its SO_2 program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each utility unit must surrender one allowance for each ton of SO_2 that it emits. Emission sources that install controls and no longer need all of their allowances can bank those allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NOx emissions through the use of available combustion controls. Units must meet NOx emission rates standards which are specific to that unit or units may participate in an annual averaging program for utility units that are under common control.

Future Reduction Requirements for SO_2, NOx, and Mercury

In 1997, the Federal EPA adopted new, more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter and ground-level ozone non-attainment areas. The Federal EPA has identified SO_2 and NOx emissions as precursors to the formation of fine particulate matter. NOx emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NOx and SO_2 from the AEP System's generating units are highly probable. In addition, the Federal EPA has proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation, known as the Clear Skies Act, was introduced in Congress and is supported by the Bush Administration. This legislation would regulate NOx, SO_2, and mercury emissions from electric generating plants. AEP supports enactment of this comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. Management believes the Bush Administration's Clear Skies Act would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. Although the prospects for enactment of the Clear Skies Act are low, there are alternative regulatory approaches which will likely require the AEP System to substantially reduce SO_2, NOx and mercury emissions over the next ten years.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO_2, NOx and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed an interstate air quality rule for reducing SO_2 and NOx emissions across the eastern half of the United States (29 states and the District of Columbia) to address attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The interstate air quality rule would require affected states to include, in their SIPs, a program to reduce NOx and SO_2 emissions from coal-fired electric utility units. SO_2 and NOx emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO_2 emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NOx emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO_2 and NOx trading programs have not yet been proposed.

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

The Federal EPA recommends, and AEP supports, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO_2 and NOx reduction requirements imposed on the same sources under the proposed interstate air quality rule. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, that can be used to comply with the more stringent SO_2 and NOx requirements, have also proven highly effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018.

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

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that AEP subsidiaries will invest in additional conventional pollution control technology on a major portion of their coal-fired power plants. Finalization of new requirements for further SO_2, NOx and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control.

Estimated Air Quality Environmental Investments

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

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

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

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

All of the costs discussed below are incremental to the AEP subsidiaries' current investment base and operating cost structure. These expenditures for pollution control technologies, replacement generation and associated operating costs are recoverable from customers through regulated rates (in regulated jurisdictions) and should be recoverable through market prices (in deregulated jurisdictions). If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Estimated Investments for NOx Compliance

Management estimates that AEP subsidiaries will make future investments of approximately $600 million to comply with the Federal EPA's NOx Rule, the Texas Commission on Environmental Quality Rule and other final Federal EPA NOx-related requirements. Approximately $500 million of these investments are reflected in the estimated construction expenditures for 2004 – 2006. As of December 31, 2003, the AEP System has invested approximately $1.1 billion to comply with various NOx requirements. Estimated future compliance costs, amounts in the 2004 – 2006 construction budget and amounts spent by subsidiaries are as follows:

	Future Estimated Compliance Investment	Investment Amount in 2004 – 2006 Budget	Amount Spent
		(in millions)	
AEGCo	$10	$9	$12
APCo	151	151	307
CSPCo	63	29	71
I&M	10	9	17
KPCo	11	1	179
OPCo	305	273	442
PSO	8	8	-
SWEPCo	18	12	23
TCC	-	-	5

Estimated Investments for SO2 Compliance

The AEP System is complying with Title IV SO_2 requirements by installing scrubbers, other controls and fuel switching at certain generating units. AEP subsidiaries also use SO_2 allowances that were:

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

Decreasing SO_2 allowance allocations, a diminishing SO_2 allowance bank, and increasing allowance prices in the market will require the installation of additional controls on certain generating units. AEP subsidiaries plan to install 3,500 MW of additional scrubbers over the next 4 years to comply with our Title IV SO_2 obligations. In total management estimates these additional capital costs to be approximately $1.2 billion. Of this total, approximately $900 million will be expended during 2004-2006 and this amount is included in total estimated construction expenditures for 2004 – 2006. The following table shows the estimated additional capital costs and amounts included in the 2004 – 2006 budget for additional scrubbers by subsidiary:

	Cost of Additional Scrubbers	Amount in 2004 – 2006 Construction Budget
	(in millions)	
APCo	$367	$307
OPCo	753	542
SWEPCo	27	21
TNC	16	16

Estimated Investments to Comply with Future Reduction Requirements

The AEP System's planning assumptions for the levels and timing of emissions reductions parallel the reduction levels and implementation time periods stated in the proposed rules issued by the Federal EPA in January 2004. Management has also assumed that the Federal EPA will implement a mercury trading option and will design its proposed cap and trade mechanism for SO_2, NOx and mercury emissions in a manner similar to existing cap and trade programs. Based on these assumptions, compliance would require additional capital investment of approximately $1.7 billion by 2010, the end of the first phase for each proposed rule. Management estimates that the subsidiaries will invest $200 million of this amount through 2006, and this amount is included in our total estimated construction expenditures for 2004 – 2006.

	Estimated Compliance Investments	Amount in 2004 – 2006 Budget
	(in millions)	
APCo	$698	$79
CSPCo	184	4
KPCo	295	36
OPCo	454	103
SWEPCo	94	-

Management also estimates that the subsidiaries would incur increases in variable operation and maintenance expenses of $150 million for the periods by 2010, due to the costs associated with the maintenance of additional control systems, disposal of scrubber by-products and the purchase of reagents.

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

Beyond 2010, the AEP System expects to incur additional costs for pollution control technology retrofits and associated operation and maintenance of the equipment. Management cannot estimate these additional costs because of the uncertainties associated with the final control requirements and the associated compliance strategy, but these capital and operating costs will be significant.

New Source Review Litigation

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

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

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

Superfund and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generation plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and non-hazardous materials. AEP subsidiaries are currently incurring costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized the Federal EPA to administer the clean-up programs. As of year-end 2003, APCo, CSPCo, I&M and OPCo are each named by the Federal EPA as a PRP for one site. There are six additional sites for which APCo, CSPCo, I&M, KPCo, OPCo and SWEPCo have received information requests which could lead to PRP designation. OPCo and TCC have also been named potentially liable at four sites under state law. Liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where AEP subsidiaries have been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

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

Global Climate Change

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO_2, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not submitted to the Senate for its advice and consent by President Clinton. In March 2001, President Bush announced his opposition to the treaty. Ratification of the treaty by a majority of the countries' legislative bodies is required for it to be enforceable. Enforceability of the protocol is now contingent on ratification by Russia, which has expressed concerns about doing so.

On August 28, 2003, the Federal EPA issued a decision in response to a petition for rulemaking seeking reductions of CO_2 and other greenhouse gas emissions from mobile sources. The Federal EPA denied the petition and issued a memorandum stating that it does not have the authority under the CAA to regulate CO_2 or other greenhouse gas emissions that may affect global warming trends. The Circuit Court of Appeals for the District of Columbia is reviewing these actions.

AEP does not support the Kyoto Protocol but has been working with the Bush Administration on a voluntary program aimed at meeting the President's goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, AEP has been a leader in pursuing voluntary actions to control greenhouse gas emissions. AEP expanded its commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program, under which AEP's subsidiaries are obligated to reduce or offset 18 million tons of CO_2 emissions during 2003-2006.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law I&M and TCC participate in the DOE's SNF disposal program which is described in Note 7. Since 1983 I&M has collected $316 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. We deposited $117 million of these funds in external trust funds to provide for the future disposal of SNF and remitted $199 million to the DOE. TCC has collected and remitted to the DOE, $56 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date, the DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of TCC and the other STP owners, along with a number of 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 proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other 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. On January 17, 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continues on the issue of damages owed to I&M by the DOE with a trial scheduled in March 2004. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2003 estimate the cost to decommission the Cook Plant ranges from $821 million to $1.08 billion in 2003 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2003, the total decommissioning trust fund balance for Cook Plant was $720 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate TCC'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, 2003, the total decommissioning trust fund for TCC's share of STP was $125 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. I&M and TCC will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Clean Water Act Regulation

On February 16, 2004, the Federal EPA signed a rule pursuant to the Clean Water Act that will require all large existing power plants to meet certain performance standards to reduce the mortality of juvenile and adult fish or other larger organisms pinned against a plant's cooling water intake screens. A subset of these plants that are located on sensitive water bodies will be required to meet additional performance standards for reducing the number of smaller organisms passing through the water screens and the cooling system. Sensitive water bodies are defined as oceans, estuaries, the Great Lakes, and small rivers with large plants. These rules will result in additional capital and operation and maintenance expenses to ensure compliance.

Other Environmental Concerns

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

Critical Accounting Policies

In the ordinary course of business, we use a number of estimates and assumptions relating to the reporting of results of operations and financial condition in the preparation of our financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ significantly from those estimates under different assumptions and conditions. We believe that the following discussion addresses the most critical accounting policies, which are those that are most important to the portrayal of the financial condition and results and require management's most difficult, subjective and complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain.

Revenue Recognition

Regulatory Accounting

The consolidated financial statements of the registrant subsidiary companies with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo), reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers through regulated revenues in the same accounting period. Regulatory liabilities (unrealized gains) or regulatory assets (unrealized losses) are also recorded for changes in the fair value of physical and financial contracts that meet the definition of a derivative as defined in SFAS 133 and are subject to the regulated ratemaking process.

When regulatory assets are probable of recovery through regulated rates, certain registrant subsidiaries record them as assets on the balance sheet. Registrant subsidiaries test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If registrant subsidiaries determine that recovery of a regulatory asset is no longer probable, they write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized and recorded when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Energy Marketing and Risk Management Activities

Registrant subsidiaries engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in October 2002, these activities were focused on wholesale markets where registrant subsidiaries own assets. Registrant subsidiaries activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, registrant subsidiaries recorded wholesale marketing and risk management activities using the mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. Registrant subsidiaries implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into prior to October 25, 2002, registrant subsidiaries implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change.

After January 1, 2003, registrant subsidiaries use mark-to-market accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and rescission of EITF 98-10 in Note 2.

All of the registrant subsidiaries except AEGCo participate in wholesale marketing and risk management activities in electricity and gas. For I&M, KPCo, PSO and a portion of TNC and SWEPCo, when the contract settles the total gain or loss is realized in revenues. Where the revenues are recorded on the income statement depends on whether the contract is subject to the regulated ratemaking process. For contracts subject to the regulated ratemaking process the total gain or loss realized for sales and the cost of purchased energy are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts subject to the regulated ratemaking process are deferred as regulatory liabilities (gains) or regulatory assets (losses). For contracts not subject to the ratemaking process only the difference between the accumulated unrealized net gains or losses recorded in prior periods and the cash proceeds are recognized in the income statement as nonoperating income. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts not subject to the ratemaking process are included in nonoperating income on a net basis. Unrealized mark-to-market gains and losses are included in the balance sheet as Risk Management Assets or Liabilities as appropriate.

For APCo, CSPCo and OPCo, depending on whether the delivery point for the electricity is in the traditional marketing area or not determines where the contract is reported in the income statement. Physical forward risk management sale and purchase contracts with delivery points in the traditional marketing area are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in the traditional marketing area are also included in revenues on a net basis. Physical forward sale and purchase contracts for delivery outside of the traditional marketing area are included in nonoperating income when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of the traditional marketing area are included in nonoperating income on a net basis.

Accounting for Derivative Instruments

For derivative contracts that are not designated as hedges or normal purchase and sale transactions, registrant subsidiaries recognize unrealized gains and losses prior to settlement based on changes in fair value during the period in our results of operations. When registrant subsidiaries settle mark-to-market derivative contracts and realize gains and losses, registrant subsidiaries reverse previously recorded unrealized gains and losses from mark-to-market valuations.

Registrant subsidiaries designate certain derivative instruments as hedges of forecasted transactions or future cash flows (cash flow hedges) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). Registrant subsidiaries report changes in the fair value of these instruments on our balance sheet. Registrant subsidiaries do not recognize changes in the fair value of the derivative instrument designated as a hedge in the current results of operations until earnings are impacted by the hedged item. Registrant subsidiaries also recognize any changes in the fair value of the hedging instrument, that are not offset by changes in the fair value of the hedged item, immediately in earnings.

Registrant subsidiaries measure the fair values of derivative instruments and hedge instruments accounted for using mark-to-market accounting based on exchange prices and broker quotes. If a quoted market price is not available, registrant subsidiaries estimate the fair value based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Registrant subsidiaries reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. There are inherent risks related to the underlying assumptions in models used to fair value open long-term derivative contracts. Registrant subsidiaries have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Registrant subsidiaries recognize all derivative instruments at fair value in our balance sheets as either Risk Management Assets or Risk Management Liabilities. Registrant subsidiaries do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in revenues in the income statements on a net basis.

Long-Lived Assets

Long-lived assets are evaluated periodically for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. If the carrying amount is not recoverable, an impairment is recorded to the extent that the fair value of the asset is less then its book value.

Pension Benefits

AEP sponsors pension and other retirement plans in various forms covering all employees who meet eligibility requirements. AEP uses several statistical and other factors which attempt to anticipate future events in calculating the expense and liability related to its plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, AEP's actuarial consultants use subjective factors such as withdrawal and mortality rates to estimate these factors. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded. See "Pension Plans" in the Significant Factors section of Registrants' Combined Management's Discussion and Analysis for additional discussion.

New Accounting Pronouncements

Effective July 1, 2003, we implemented FIN 46, "Consolidation of Variable Interest Entities." As a result of the implementation, we consolidated two entities, Sabine Mining Company ($77.8 million) and JMG Funding, LP ($469.6 million), which were previously off-balance sheet. These entities were consolidated with SWEPCo and OPCo, respectively. There is no change in net income due to the consolidations. In addition, we deconsolidated the trusts which hold mandatorily redeemable trust preferred securities which were previously reported as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries ($321 million). As a result of the deconsolidation these amounts are now included in Long-term Debt. In December 2003, the FASB issued FIN 46R which replaces FIN 46. The

FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

See Notes 1 and 2 of the Notes to Respective Financial Statements for a discussion of significant accounting policies and additional impacts of new accounting pronouncements.

Other Matters

FERC Proposed Standard Market Design

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments that the FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until any potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

Seasonality

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

ATTACHMENT 2 TO AEP:NRC:4071-01

INDIANA MICHIGAN POWER COMPANY
PROJECTED CASH FLOW FOR THE YEAR 2004

Indiana Michigan Power Co.
2004 Forecasted Internal Cash Flow
$ Millions

	2004
Net Income	169.9
Less: Common & Preferred Dividends	120.8
	49.1
Adjustments:	
Depreciation and Amortization	175.3
Amortization of Deferred Operating Costs	67.5
Deferred Federal Income Taxes and Investment Tax Credits	(13.4)
Allowance for Equity Funds Used During Construction	(4.2)
Changes in Working Capital	(58.9)
Total Adjustments	166.3
Internal Cash Flow	215.4
Average Quarterly Cash Flow	53.9
Average Cash Balances and Short-Term Investments	18.8
Total	72.7

Projected