UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended SEPTEMBER 30, 2003
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ---- to ----

Commission File Number	Registrant, State of Incorporation Address, and Telephone Number	I.R.S. Employer Identification No.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
0-18135	AEP GENERATING COMPANY (An Ohio Corporation)	31-1033833
0-346	AEP TEXAS CENTRAL COMPANY (A Texas Corporation)	74-0550600
0-340	AEP TEXAS NORTH COMPANY (A Texas Corporation)	75-0646790
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation)	61-0247775
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
All Registrants	1 Riverside Plaza, Columbus, Ohio 43215-2373 Telephone (614) 716-1000	

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Sections 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes X No

Indicate by check mark whether American Electric Power Company, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes X No

Indicate by check mark whether AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are accelerated filers (as defined in Rule 12b-2 of the Exchange Act).

Yes No X

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

The number of shares outstanding of American Electric Power Company, Inc. Common Stock, par value $6.50, at October 31, 2003 was 395,007,320.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORT ON FORM 10-Q
September 30, 2003

This combined Form 10-Q is separately filed by 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 and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

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

Term	Meaning
2004 True-up Proceeding	A filing to be made after January 10, 2004 under the Texas Legislation to finalize the amount of stranded costs and the recovery of such costs.
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEPR.
AEPR	AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP Power Pool	AEP System Power Pool. Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale system sales of the member companies.
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.
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.
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.
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."
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.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
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.
PJM	Pennsylvania - New Jersey - Maryland regional transmission organization.
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.
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, Amendment of Statement 133 on Derivative Instruments and Hedging Activities.

SFAS 150	Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.
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.
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

These reports made by AEP and its registrant subsidiaries contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and 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:

o Electric load and customer growth.
o Abnormal weather conditions.
o Available sources and costs of fuels.
o Availability of generating capacity.
o The speed and degree to which competition is introduced to our service territories.
o The ability to recover stranded costs in connection with deregulation.
o New legislation and government regulation including requirements for reduced emissions of sulfur, nitrogen, carbon and other substances.
o Pending and future rate cases and negotiations.
o Oversight and/or investigation of the energy sector or its participants.
o Our ability to successfully control costs.
o The success of disposing of existing investments that no longer match our corporate profile.
o International and country-specific developments affecting foreign investments including the disposition of any current foreign investments.
o The economic climate and growth in our service territory and changes in market demand and demographic patterns.
o Inflationary trends.
o Accounting pronouncements periodically issued by accounting standard-setting bodies.
o The performance of AEP's pension plan.
o Electricity and gas market prices.
o Interest rates.
o Liquidity in the banking, capital and wholesale power markets.
o Actions of rating agencies.
o Changes in technology, including the increased use of distributed generation within our transmission and distribution service territory.
o Other risks and unforeseen events, including wars, the effects of terrorism, embargoes and other catastrophic events.

Results of Operations

American Electric Power Company's consolidated Net Income (Loss) by operating segment for the third quarter and nine months ended September 30, 2003 and 2002 were as follows:

	Third Quarter		Nine Months Ended	
	2003	2002	2003	2002
	(in millions)			
Utility Operations	$372	$405	$886	$846
Investments - Gas Operations	(20)	5	(59)	(75)
Investments - UK Operations	(51)	(5)	(88)	6
Investments - Other	(44)	(19)	(44)	(74)
Continuing Operations	257	386	695	703
Discontinued Operations	-	39	(16)	(35)
Cumulative Effect of Accounting Changes	-	-	193	(350)
Total Net Income	$257	$425	$872	$318

Third Quarter 2003 Compared to Third Quarter 2002

Our Net Income for the third quarter of 2003 is discussed below according to the operating segments listed above. Income from Continuing Operations (or Income Before Discontinued Operations and Cumulative Effect of Accounting Changes) for the quarter was negatively affected by the weather, weak economy and the availability of electric generation. Third quarter 2003 Net Income was $257 million or $0.65 per share compared to $425 million or $1.25 per share in 2002. In March 2003 common stock was issued which caused $0.11 per share dilution in the current quarter.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Our Net Income for Nine Months Ended is discussed below according to the operating segments listed above. Income from Continuing Operations (or Income Before Discontinued Operations and Cumulative Effect of Accounting Changes) was negatively affected by the weather, weak economy and the availability of electric generation. 2003 Net Income of $872 million or $2.28 per share includes a loss on discontinued operations of $16 million (net of tax) (see Note 8), $242 million (net of tax) of Income from the Cumulative Effect of Accounting Changes in the first quarter resulting from the implementation of SFAS 143 (see Note 3), partially offset by $49 million (net of tax) of Loss from the Cumulative Effect of Accounting Changes in the first quarter resulting from the implementation of EITF 02-3 (see Note 3). 2002 Net Income of $318 million or $0.97 per share includes a loss on discontinued operations of $35 million (net of tax) (see Note 8) and a $350 million (net of tax) charge for the implementation of SFAS 142 (see Note 3). A common stock issuance in March 2003 caused a $0.37 per share dilution in the nine-month period.

Utility Operations

Summary of Selected Sales Data
For Utility Operations

	Third Quarter 2003	Third Quarter 2002	Nine Months Ended 2003	Nine Months Ended 2002
	(in millions of KWH)			
ENERGY SUMMARY				
Retail				
Residential	12,606	13,405	34,813	35,781
Commercial	10,341	10,118	28,082	27,797
Industrial	12,932	13,154	38,620	40,287
Miscellaneous	829	891	2,258	2,059
Total	36,708	37,568	103,773	105,924
Wholesale	22,093	20,938	56,385	53,393
	(in degree days)			
WEATHER SUMMARY				
EASTERN REGION				
Actual - Heating	78	22	3,444	2,910
Normal - Heating	80	80	3,298	3,340
Actual - Cooling	618	916	782	1,269
Normal - Cooling	708	701	1,002	992
WESTERN REGION				
Actual - Heating	-	-	839	789
Normal - Heating	-	-	840	829
Actual - Cooling	1,386	1,438	1,941	2,063
Normal - Cooling	1,398	1,396	1,919	1,910

Third Quarter 2003 Compared to Third Quarter 2002

Net Income for Utility Operations, our core business, decreased by $33 million due to a decrease in operating income.

Our operating income decreased in the third quarter primarily due to:

o A reduction in pre-tax earnings of $89 million for the loss of contributions from our two Texas retail electricity providers that we sold to Centrica in December 2002. The demand from our two Texas retail providers was replaced, in part, with a power supply contract with Centrica that extends through 2004. Our Texas supply margins also decreased due to an outage at our STP nuclear plant and the related higher costs of replacement power. Our Texas supply represents the gross margin for output of generating units in the ERCOT region and from "reliability must run" (RMR) contracts with ERCOT.

o Retail margins from our regulated integrated utilities, which reduced pre-tax earnings by $71 million due to lower demand from the combined impact of weather and a continued weak economy.

o Reduced demand in our Ohio Companies resulting from mild weather and economic pressures on industrial customers, which reduced pre-tax earnings by $15 million.

Our operating income decrease was partially offset by:

o Pre-tax earnings from our Texas distribution operations (Texas wires), which increased $19 million primarily from the $61 million non-cash earnings associated with the capacity auction true-up in Texas. 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. We filed a plan of divestiture with the PUCT in December 2002, enabling us to record a regulatory asset associated with stranded cost recovery. Our regulatory asset is expected to be recovered through the 2004 true-up proceeding established by deregulation laws in Texas.

o Pre-tax earnings for systems sales, which increased $76 million in the current quarter due to low cost generation that was available because of weather-related reductions in retail demand, favorable power optimization and higher peak prices in ECAR.

o A $13 million decrease in Taxes Other Than Income Taxes primarily caused by reduced gross receipts tax due to the sale of the Texas REPs.

o A $15 million decrease in Maintenance and Other Operation expenses due to ongoing efforts to reduce costs despite incurring higher storm damage repair costs in the current quarter.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Net Income for Utility Operations increased $40 million due primarily to an $85 million increase in operating income partially offset by an increase in nonoperating expenses.

Our operating income increased primarily due to:

o Texas wires pre-tax earnings, which increased $137 million primarily from $169 million in non-cash earnings associated with the capacity auction true-up in Texas.

o Pre-tax earnings for systems sales, transmission revenue and other wholesale transactions, which increased $141 million due to low cost generation that was available because of weather-related reductions in retail demand, favorable power optimization, higher peak prices and increased sales in ECAR. In addition, we experienced higher third-party transmission volumes and recognized a loss on the settlement of a long-term contract with the Public Utility District No. 1 of Snohomish County, Washington (see Significant Factors - Litigation).

o Other operating revenue, which increased $29 million due to associated business development in Western non-regulated companies for the construction of transmission lines, services fees, pole attachments and transmission rentals.

o Maintenance and Other Operation expense, which decreased $39 million due to ongoing efforts to reduce costs despite severe storm damage in the Midwest.

o A $28 million decrease in Taxes Other Than Income Taxes primarily caused by reduced gross receipts tax due to the sale of the Texas REPs.

o Depreciation and Amortization, which decreased by $28 million due to the change in accounting for asset retirement obligations as mandated by SFAS 143. This decrease, however, is offset by similar increases in Maintenance and Other Operation expenses.

Our operating income increase was partially offset by:

o Retail margins from our regulated integrated utilities, which reduced pre-tax earnings by $132 million due to the combined impacts of weather, a continued weak economy and replacement power costs associated with our Cook Plant outages.

o Lower demand at our Ohio Companies, which reduced pre-tax earnings by $11 million. This reduced demand was attributable to mild weather and economic pressures on industrial customers.

o A reduction in pre-tax earnings of $173 million for the loss of contributions from our two Texas retail electricity providers that we sold to Centrica in December 2002. The demand from our two Texas retail providers was replaced, in part, with a power supply contract with Centrica that extends through 2004. Our Texas supply margins also decreased due to an outage at our STP nuclear plant and a separate provision for potential disallowance by the PUCT of certain historical fuel expenses. Our Texas supply represents the gross margin for output of generating units in the ERCOT region and from "reliability must run" (RMR) contracts with ERCOT.

Investments - Gas Operations

Third Quarter 2003 Compared to Third Quarter 2002

Net Loss from our Gas Operations, which includes Louisiana Intrastate Gas and Houston Pipe Line operations, increased $25 million from the comparable quarter in 2002 due to lower margins resulting from our reduced risk profile and MTM gains recorded on contracts during the third quarter of 2002, which did not recur during 2003. The increased loss was partially offset by reduced operating expenses of $4 million.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Net Loss from our Gas Operations of $59 million decreased $16 million from the comparable period in 2002. We reduced Operating expenses by $22 million and interest expense by $8 million. These favorable factors are partially offset by reductions in margins resulting from our reduced risk profile and MTM gains, which did not recur during 2003.

Investments - UK Operations

Third Quarter 2003 Compared to Third Quarter 2002

Net Loss from our UK Operations, which includes Fiddler's Ferry and Ferrybridge plants (FFF), increased by $46 million. During the third quarter, pre-tax gross margins declined by $54 million driven by timing differences which result in losses on coal and financial freight contracts that are marked-to-market and that are not offset during the quarter by mark-to-market gains on physical freight contracts because physical freight contracts are accounted for on a settlement basis. Our net loss was also greater due to reduced trading activity and weaker power trading margins. Operation and maintenance expense increased by $14 million due to incentives, severance and corporate charges. The operating loss in the current quarter was partially offset by reduced income taxes.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Net Loss from our UK Operations increased by $94 million due to the reductions in operating income. During the period, pre-tax gross margins declined due to timing differences in the accounting treatment for physical freight versus hedging transactions noted above. Our net loss was also driven by increases in operations and maintenance costs, which included severance and redundancy costs of the Nordic trading office.

Investments - Other

Third Quarter 2003 Compared to Third Quarter 2002

Net Loss from our Other investments, which consists of investments in independent power plants, coal mines, river transportation, and communications, was $44 million in the third quarter of 2003, an increase of $25 million over the comparable quarter in 2002. During the third quarter of 2003, two of our independent generation facilities became impaired and we recognized a loss of $45 million. This loss was partially offset by favorable variances caused by the 2002 wind-down of our communications operations, a Vale impairment in 2002, and 2002 pre-tax losses for investments in Dynetec and Altra Energy, which did not recur in 2003. AEP Pro Serv's (Pro Serv) operating margins decreased by $4 million during 2003 from the comparable quarter in 2002.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Net Loss from our Other investments decreased by $30 million due to lower international development costs, reduced interest expense and lower costs to wind-down operations. These decreases were partially offset by our impairment of two of our independent generation facilities during 2003. Pro Serv's operating margins decreased by $19 million during 2003 from the comparable period in 2002.

Financial Condition

Credit Ratings

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
Senior Notes issued by AEP Resources (with support agreement from AEP)	Baa3	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 our rated subsidiaries. The reviews resulted in downgrades of certain debt ratings. The completion of these reviews was a culmination of rating actions started during 2002.

Liquidity

At September 30, 2003, our liquidity sources totaled $4.6 billion and we had an available liquidity position of $4.2 billion as illustrated in the table below:

Credit Facilities	(in millions)	Maturity
Commercial Paper Backup:		
Lines of Credit	$ 750	5/04
Lines of Credit	1,000	5/05
Lines of Credit	750	5/06
Euro Revolving Credit Facilities	351*	10/03
Letter of Credit Facility	200	9/06
Total	3,051	
Liquidity Reserves	300**	
Other Temporary Investments	1,234**	
Total Liquidity Sources	4,585	
Less: Commercial Paper Outstanding	427	
Letter of Credit Outstanding	8	
Total Available Liquidity	$4,150	

* One of the Euro Revolving Credit Facilities has expired and has not been renewed. The remaining facility was renewed, for a one-year term, in the amount of 150 million (Euro) during October 2003.

** Liquidity Reserves, Other Temporary Investments and $174 million of operational cash on hand make up the $1,708 million Cash and Cash Equivalents balance on our Consolidated Balance Sheet at September 30, 2003. We maintain the $300 million cash liquidity reserve fund to support our marketing operations in the U.S. and keep additional cash on hand as market conditions change.

In April 2003, our Board of Directors reduced the quarterly common stock dividend to $0.35 per share, which was a 42% decrease from the previous dividend of $0.60 per share. This reduction will result in annual cash savings of approximately $395 million.

Cash Flow

	Nine Months Ended 2003	2002
	(in millions)	
Cash and cash equivalents at beginning of period	$1,213	$224
Net cash from (used for) continuing operations:		
Operating activities	1,553	746
Investing activities	(885)	(19)
Financing activities	(173)	(397)
Effect of exchange rate changes on cash and cash equivalents	-	(3)
Net increase in cash and cash equivalents	495	327
Cash and cash equivalents at end of period	$1,708	$551

Cash from operations, a bank-sponsored receivables purchase agreement and short-term borrowings provide working capital and meet other short-term cash needs. We generally use short-term borrowings to fund 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. We operate a money pool and sell accounts receivables (through the agreement referenced above) to provide liquidity for the domestic electric subsidiaries. Short-term borrowings are supported by three revolving credit agreements.

Operating Activities

Cash flows from operating activities during the first nine months of 2003 were $1,553 million. Beginning with Income Before Discontinued Operations and Cumulative Effect of Accounting Changes of $695 million, we add depreciation, amortization and deferred taxes of $1,334 million and deduct $169 million of non-cash ECOM, $83 million in mark-to-market changes and $296 million for working capital changes. The negative working capital changes include $90 million paid to Williams Companies in settlement for power and gas transactions, and $59 million in increased fuel inventories.

Investing Activities

Cash flows used for investing activities during the first nine months of 2003 were $885 million compared to $19 million during 2002. The major reason for the year-over-year variance was a construction expenditures reduction of $196 million in 2003 and proceeds of $1,116 million from the sale of assets in 2002. The 2002 sale of assets was part of our plan to sell non-core investments and improve our liquidity.

Total consolidated plant and property additions for the first nine months of 2003 were $941 million, including continued construction expenditures for emission control technology at several coal-fired generating plants (see Note 6).

Financing Activities

Cash flows used for financing activities in the first nine months of 2003 decreased by $224 million compared to 2002, primarily as the result of AEP's reduction in the common stock dividend. During the first nine months of 2003, AEP retired $4,789 million of debt ($2,825 million short-term and $1,964 million of long-term) and increased available cash primarily through the issuance of long-term financing ($4,146 million), the issuance of common stock ($1,177 million) and the generation of cash from operating activities. Also, see Note 12 for further information on financing activities.

Significant Factors

Possible Divestitures

We are firmly committed to continually evaluate the need to reallocate resources to areas that effectively match our investments with our business strategy and provide the greatest potential for financial returns. Similarly, we are committed to disposing of investments that no longer meet these principles.

We are seeking to divest substantially all of our non-regulated assets including domestic and international unregulated generation, gas pipelines, a coal business, independent power producers (IPP) 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 5). We expect to receive final bids in the fourth quarter of 2003.

During the second quarter of 2003, we also hired an advisor to evaluate our coal business, which has resulted in receipt of non-binding bids. We are currently evaluating these bids.

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 in the fourth quarter of 2003.

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 have declines in fair value that are other than temporary in nature. As a consequence, we recorded an impairment of $70 million ($45.5 million net of tax) in the third quarter of 2003. During the fourth quarter of 2003, we distributed an information memorandum related to the possible sale of our interest in these IPPs.

During the fourth quarter of 2003, we selected an advisor for the disposition of our UK business. We are evaluating the market for possible disposition of these UK assets prior to our assumed date of year-end 2004.

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. If we choose to dispose of these assets, we may realize non-recurring losses in the aggregate that could have a material impact on our results of operations, cash flows and financial condition.

Corporate Separation

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), we sought regulatory approval to separate our regulated and unregulated operations. With the changes in our business strategy in response to energy market and business conditions, management continues to evaluate corporate separation plans, including determining whether legal corporate separation is appropriate in jurisdictions where it is not legally required.

RTO Formation

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), 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 the 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. In July 2003, the KPSC ruled, in part, that we had failed to prove the benefit of our PJM RTO membership to Kentucky retail customers and denied our request for approval of transfer of functional control to PJM. In August 2003, AEP sought and received rehearing of the KPSC's order, allowing us to file additional evidence in this proceeding. 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 specified conditions. Proceedings in the other states remain pending.

In February 2003, Virginia enacted legislation that prohibited the transfer of transmission assets in its jurisdiction to an RTO until, at the earliest, July 2004 and only with the approval of Virginia SCC.

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.

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 $23 million for the entire PJM integration project). AEP also has $24 million, at September 30, 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. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

On September 29 and 30, 2003, the FERC held a public inquiry regarding RTO formation, including delays in AEP's participation in PJM.

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.

Industry Restructuring

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), restructuring and customer choice are in place in four of the eleven state retail jurisdictions in which our electric utility companies operate. Restructuring legislation generally provides for a transition from cost-based rate regulation of bundled electric service to customer choice and market pricing for the supply of electricity. The status of our transition plans, regulatory issues and proceedings in various state regulatory jurisdictions is presented in Note 5.

Restructuring legislation in Texas provides that the PUCT address several issues in the 2004 true-up proceeding. One of these issues is the wholesale capacity auction true-up. TCC has recorded $431 million of regulatory assets and related revenues through September 30, 2003 based upon our estimate.

In July 2003, the PUCT Staff published their proposed filing package for the 2004 true-up proceeding. Within the filing package are instructions and sample schedules that demonstrate the calculation of the wholesale capacity auction true-up. That calculation differs from the methodology being employed by TCC. TCC filed comments on the proposed 2004 true-up filing package in September 2003 and took exception to the methodology employed by the PUCT Staff. A true-up filing package will probably be approved by the PUCT in the fourth quarter of 2003. If the PUCT Staff's methodology is approved, TCC's wholesale capacity auction true-up regulatory asset could require adjustment.

In October 2003, a coalition of consumer groups (the Coalition of Ratepayers) including the Office of Public Utility Counsel, the State of Texas, Cities served by CPL and Texas Industrial Energy Consumers filed a petition with the PUCT requesting that the PUCT initiate a rulemaking to amend the PUCT's stranded cost true-up rule (True-up Rule). The Coalition of Ratepayers proposed to amend the True-up Rule to revise the calculation of the wholesale capacity auction true-up. If adopted, the Coalition of Ratepayers' proposal would substantially reduce or possibly eliminate the wholesale capacity auction true-up regulatory asset that TCC has accrued in 2002 and 2003. The PUCT requested that responses to the Coalition of Ratepayers' petition be filed by November 7, 2003. On November 5, 2003, the PUCT denied the Coalition of Ratepayers' petition.

See Notes 4 and 5 for further discussion.

In the event we are unable, after the 2004 true-up proceeding, to recover all or a portion of our generation-related regulatory assets, unrecovered fuel balances, stranded costs, 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.

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. 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

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), AEPSC, APCo, CSPCo, I&M, and OPCo are involved in litigation regarding generating plant emissions under the Clean Air Act. The Federal EPA and a number of states alleged APCo, CSPCo, I&M, OPCo and eleven unaffiliated utilities made modifications to generating units at coal-fired generating plants in violation of the Clean Air Act. The Federal EPA filed complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20-year period.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the Clear Air Act proceedings and is 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. In the event that 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. See Note 6 for further discussion.

NOx Reductions

The Federal EPA issued a NOx Rule and adopted a revised rule (the Section 126 Rule) under the Clean Air Act requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. The compliance date for the rules is May 31, 2004.

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

We are installing selective catalytic reduction (SCR) technology and other combustion control technology to reduce NOx emissions on certain units to comply with these rules.

Our estimates indicate that compliance with the rules could result in required capital expenditures in a range of approximately $1.3 billion to $1.7 billion for the AEP System of which approximately $1 billion has been spent through September 30, 2003. The actual cost to comply could be significantly different than these estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital or operating costs for additional pollution control equipment are recovered from customers, these costs would adversely affect future results of operations, cash flows and possibly financial condition. See Note 6 for further discussion.

Enron Bankruptcy

In 2002, certain subsidiaries of AEP filed claims in the bankruptcy proceeding of Enron Corporation and its subsidiaries which is pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, AEP and its subsidiaries had open trading contracts and trading accounts receivables and payables with Enron. We also have various HPL related contingencies and indemnities from Enron including issues related to the underground Bammel gas storage facility and the cushion gas (pad gas) required for its normal operation.

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. 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 ultimate resolution of these issues or their impact on results of operations, cash flows and financial condition. See Note 6 for further discussion.

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 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 approximately $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 6 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

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), 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.

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. Although management is unable to predict the outcome of this case, it is not expected to have a material effect on results of operations or cash flows.

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 6 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 6 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.

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 6 for further discussion.

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 as part of our trading activity using MTM accounting. As a result, we incurred a $10 million pre-tax loss.

Other Litigation

We continue to be involved in certain other legal matters discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003).

Critical Accounting Policies

See "Registrants' Combined Management's Discussion and Analysis of Financial Condition, Accounting Policies and Other Matters - Critical Accounting Policies" in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

New Accounting Pronouncements

See Note 3 for a discussion of new accounting pronouncements.

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.

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

AEP has actively participated in the Committee of Chief Risk Officers (CCRO) to develop standard disclosures for risk management activities around energy trading contracts. The CCRO is composed of the chief risk officers of major electricity and gas companies in the United States. Recently the CCRO adopted disclosure standards for energy contracts to improve clarity, understanding and consistency of information reported. Implementation of the new disclosures is voluntary. AEP supports the work of the CCRO and has embraced the new disclosures. The following tables provide information on AEP's risk management activities.

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

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

Roll-Forward of MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2003

	Utility Operations	Gas Operations	UK Operations	Consolidated
		(in millions)		
Beginning Balance December 31, 2002	$360	$(155)	$ 45	$250
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(118)	122	16	20
Fair Value of New Contracts When Entered Into During the Period (b)	-	-	-	-
Net Option Premiums Paid/(Received) (c)	1	32	(12)	21
Change in Fair Value Due to Valuation Methodology Changes	-	1	-	1
Effect of 98-10 Rescission	(19)	1	(14)	(32)
Changes in Fair Value of Risk Management Contracts (d)	42	39	(45)	36
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	4	-	-	4
Ending Balance September 30, 2003	$270	$40	$(10)	$300

(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)"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.
(e)"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.

Detail on MTM Risk Management Contract Net Assets (Liabilities)
As of September 30, 2003

	Utility Operations	Gas Operations	UK Operations	Consolidated
		(in millions)		
Current Assets	$300	$297	$362	$959
Non Current Assets	376	186	247	809
Total MTM Risk Management Contract Assets	$676	$ 483	$609	$ 1,768

Current Liabilities	$(198)	$(214)	$(420)	$ (832)
Non Current Liabilities	(208)	(229)	(199)	(636)
Total MTM Risk Management Contract Liabilities	$(406)	$(443)	$(619)	$(1,468)
Total MTM Risk Management Contract Net Assets (Liabilities)	$ 270	$40	$(10)	300
Net Non-Trading Related Derivative Contracts				(288)
Risk Management and Derivative Contract Net Assets				$12

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 AEP's total MTM asset or liability (external sources or modeled internally)
- The maturity, by year, of AEP's 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 September 30, 2003

	Remainder 2003	2004	2005	2006	2007	After 2007	Total
				(in millions)			
Utility Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$(5)	$(15)	$(3)	$(1)	$-	$-	$(24)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(1)	101	27	22	5	-	154
Prices Based on Models and Other Valuation Methods (b)	28	23	(6)	21	24	50	140
Total	$22	$109	$18	$42	$29	$50	$270
Gas Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$(64)	$96	$8	$-	$ -	$ -	$40
Prices Provided by Other External Sources - OTC Broker Quotes (a)	27	(12)	1	-	-	-	16
Prices Based on Models and Other Valuation Methods (b)	(15)	15	(3)	(6)	1	(8)	(16)
Total	$(52)	$99	$6	$(6)	$1	$(8)	$40
UK Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$-	$-	$ -	$-	$-	$-	$-
Prices Provided by Other External Sources - OTC Broker Quotes (a)	43	(50)	15	(7)	(2)	-	(1)
Prices Based on Models and Other Valuation Methods (b)	(7)		-	(1)	(1)	-	(9)
Total	$36	$(50)	$15	$(8)	$(3)	$-	$(10)
Consolidated:							
Prices Actively Quoted - Exchange Traded Contracts	$(69)	$81	$5	$(1)	$-	$-	$16
Prices Provided by Other External Sources - OTC Broker Quotes (a)	69	39	43	15	3	-	169
Prices Based on Models and Other Valuation Methods (b)	6	38	(9)	14	24	42	115
Total	$6	$158	$39	$28	$27	$42	$300

(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.

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 of the liquid portion of each energy market.

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of September 30, 2003

Domestic			Tenor (in months)
Natural Gas	Forward Purchases and Sales	NYMEX Henry Hub Gas	72
		Gas East - Northeast, Mid-continent Gulf Coast, Texas	25
		Gas West - Permian Basin, San Juan, Rocky Mtns, Kern, Cdn Border (Sumas), Malin, PGE Citygate, AECO	25
	Over the Counter Options		13
Power (Peak)	Forward Purchases and Sales	Power East - Cinergy	27
		Power East - PJM	39
		Power East - NYPP	27
		Power East - NEPOOL	27
		Power East - ERCOT	15
		Power East - TVA	0
		Power East - Com Ed	7
		Power East - Entergy	15
		Power West - PV, NP15, SP15, MidC, Mead	51
	Peak Power Volatility (Options)	Cinergy	15
	OffPeak Power Volatility	All Regions	0
Natural Gas Liquids			14
WTI Crude			48

Emissions			27
Coal			27
International			
Power		United Kingdom	36
Coal	Forward Purchases and Sales	United Kingdom	15
	Financial Transactions (Swaps)	Europe	33

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

AEP is exposed to market fluctuations in energy commodity prices impacting its power operations. AEP monitors these risks on its future operations and may employ various commodity instruments as cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from its assets. AEP dos not hedge all commodity price risk.

AEP employs 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. AEP does not hedge all interest rate risk.

AEP employs 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. AEP does 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 AEP has 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 AEP's hedging activity). The table further indicates what portions of these hedges are expected to be reclassified into the income statement 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 September 30, 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	$(172)	$(83)
Foreign Currency	(10)	(8)
Interest Rate	(11)	(5)

	------	-----
AEP Consolidated	$(193)	$(96)
	======	=====

Total Other Comprehensive Income Activity
Nine Months Ended September 30, 2003

	Power	Foreign Currency	Interest Rate	AEP Consolidated
	-----	--------	-------------	------------
	(in millions)			
Accumulated OCI, December 31, 2002	$ (3)	$(1)	$(12)	$ (16)
Changes in Fair Value (c)	(171)	(9)	3	(177)
Reclassifications from OCI to Net Income (d)	2	-	(2)	-
	------	-----	-----	------
Accumulated OCI Derivative Loss September 30, 2003	$(172)	$(10)	$(11)	$(193)
	======	=====	=====	======

(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 hedging instruments in cash flow hedges during the reporting period 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

AEP limits credit risk by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. Only after an entity has met AEP's internal credit rating criteria will we extend unsecured credit. AEP uses 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. AEP's independent analysis, in conjunction with the rating agencies information, is used to determine appropriate risk parameters. AEP also requires cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties depending upon credit quality in our normal course of business.

AEP has risk management contracts with numerous counterparties. Since AEP's open risk management contracts are valued based on changes in market prices of the related commodities, AEP's exposures change daily. AEP believes that credit and market exposures with any one counterparty is not material to AEP's financial condition at September 30, 2003. At September 30, 2003, AEP's credit exposure net of credit collateral to sub investment grade counterparties was approximately 11%, expressed in terms of net MTM assets and net receivables. As of September 30, 2003, the following table approximates counterparty credit quality and exposure for AEP based on netting across AEP 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	$1,002	$ 32	$ 970	2	$243
Split Rating	27	-	27	1	27
Non-Investment Grade	169	96	73	3	29
No External Ratings:					
Internal Investment Grade	292	7	285	1	90
Internal Non-Investment Grade	128	50	78	1	10
Total	$1,618	$185	$1,433	8	$399

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of AEP's generation facilities (based on economic availability projections) economically hedged. This information is forward-looking and provided on a prospective basis through December 31, 2005. Please note that this table is point-in time estimates, subject to changes in market conditions and AEP decisions on how to manage operations and risk.

Generation Plant Hedging Information Estimated Next Three Years As of September 30, 2003

	2003	2004	2005
Estimated Plant Output Hedged (a)	94%	92%	84%

(a) Estimated Plant Output Hedged - Represents the portion of megawatt-hours of future generation/production for which AEP has sales commitments or estimated requirements obligations to customers.

VaR Associated with Energy Trading Contracts

AEP uses a risk measurement model, which calculates Value at Risk (VaR) to measure AEP's commodity price risk in the Energy Trading portfolio. The VaR is based on the variance - covariance method using historical prices to estimate volatilities and correlations and assumes 95% confidence level and a one-day holding period. Based on this VaR analysis, at September 30, 2003, a near term typical change in commodity prices is not expected to have a material effect on AEP's 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

September 30, 2003	December 31, 2002
(in millions)	(in millions)

End	High	Average	Low	End	High	Average	Low
$7	$19	$ 7	$5	$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.

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

CCRO VaR Metrics

	End of September 30, 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	$28	$26	$71	$17
99% Confidence Level, One-Day Holding Period	$12	$11	$30	$ 7

AEP utilizes 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 AEP's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $1,156 million at September 30, 2003 and $527 million at December 31, 2002. AEP would not expect to liquidate its entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not materially affect our results of operations or consolidated financial position.

AEP is 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 settlement agreements in Michigan and West Virginia or capped in Indiana. To the extent the fuel supply of the generating units in these states is not under fixed price long-term contracts AEP is subject to market price risk. AEP continues to be protected against market price changes by active fuel clauses in Oklahoma, Arkansas, Louisiana, Kentucky, Virginia and the SPP area of Texas.

AEP employs 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. AEP engages in risk management of electricity, gas and to a lesser degree other commodities, principally coal and freight. As a result, AEP is subject to price risk. The amount of risk taken is controlled by risk management operations and AEP's Chief Risk Officer and his staff. When the risk from energy trading activities exceeds 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 Three and Nine Months Ended September 30, 2003 and 2002
(in millions, except per-share amounts)
(Unaudited)

	Three Months Ended 2003	Three Months Ended 2002	Nine Months Ended 2003	Nine Months Ended 2002
REVENUES				
Utility Operations	$3,111	$2,940	$8,512	$7,858
Gas Operations	860	700	2,791	1,803
U.K. Operations and Other	138	171	555	723
TOTAL	4,109	3,811	11,858	10,384
EXPENSES				
Fuel for Electric Generation	916	666	2,426	1,918
Purchased Electricity for Resale	206	306	626	413
Purchased Gas for Resale	828	625	2,685	1,691
Maintenance and Other Operation	977	868	2,921	3,073
Depreciation and Amortization	334	362	985	1,045
Taxes Other Than Income Taxes	179	202	524	576
TOTAL	3,440	3,029	10,167	8,716
OPERATING INCOME	669	782	1,691	1,668
Other Income	75	115	279	176
INTEREST AND OTHER CHARGES				
Investment Value and Other Impairment Losses	70	-	70	-
Other Expense	51	75	153	101
Interest	217	181	620	572
Preferred Stock Dividend Requirements of Subsidiaries	1	3	7	8
Minority Interest in Finance Subsidiary	-	9	17	27
TOTAL	339	268	867	708
INCOME BEFORE INCOME TAXES	405	629	1,103	1,136
Income Taxes	148	243	408	433
INCOME BEFORE DISCONTINUED OPERATIONS AND CUMULATIVE EFFECT	257	386	695	703
Discontinued Operations (net of tax)	-	39	(16)	(35)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (Net of Tax)				
Goodwill and Other Intangible Assets	-	-	-	(350)
Accounting for Risk Management Contracts	-	-	(49)	-
Asset Retirement Obligation	-	-	242	-
NET INCOME	$257	$425	$872	$318
AVERAGE NUMBER OF SHARES OUTSTANDING	395	339	382	329
EARNINGS (LOSS) PER SHARE				
Income Before Discontinued Operations And Cumulative Effect of Accounting Changes	$0.65	$1.14	$1.81	$2.14
Discontinued Operations	-	0.11	(0.04)	(0.10)
Cumulative Effect of Accounting Changes	-	-	0.51	(1.07)
TOTAL EARNINGS PER SHARE (BASIC AND DILUTIVE)	$0.65	$1.25	$2.28	$0.97
CASH DIVIDENDS PAID PER SHARE	$0.35	$0.60	$1.30	$1.80

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in millions)	
CURRENT ASSETS		
Cash and Cash Equivalents	$1,708	$1,213
Accounts Receivable (net)	1,535	1,740
Fuel, Materials and Supplies	1,197	1,166
Risk Management Assets	1,014	1,012
Other	901	935
TOTAL	6,355	6,066
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	18,616	17,031
Transmission	6,099	5,882
Distribution	9,815	9,573
Other (including gas, coal mining and nuclear fuel)	3,997	3,965
Construction Work in Progress	973	1,406
TOTAL	39,500	37,857
Less: Accumulated Depreciation and Amortization	16,488	16,173
TOTAL-NET	23,012	21,684
OTHER NON-CURRENT ASSETS		
Regulatory Assets	2,612	2,688
Securitized Transition Assets	703	735
Investments in Power and Distribution Projects	221	283
Goodwill	397	396
Assets Held for Sale	194	277
Assets of Discontinued Operations	-	15
Long-term Risk Management Assets	818	819
Other	1,767	1,783
TOTAL	6,712	6,996
TOTAL ASSETS	$36,079	$34,746

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$1,700	$2,030
Short-term Debt	443	3,164
Long-term Debt Due Within One Year	1,234	1,633
Risk Management Liabilities	1,029	1,113
Other	1,782	1,802
TOTAL	6,188	9,742
NON-CURRENT LIABILITIES		
Long-term Debt	12,323	8,487
Equity Unit Senior Notes	376	376
Long-term Risk Management Liabilities	791	481
Deferred Income Taxes	4,144	3,916
Deferred Investment Tax Credits	431	455
Deferred Credits and Regulatory Liabilities	837	770
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	178	185
Liabilities Held for Sale	98	130
Liabilities of Discontinued Operations	-	12
Other	2,111	1,903
Commitments and Contingencies (Note 6)		
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	83	-
TOTAL	21,372	16,715
TOTAL LIABILITIES	27,560	26,457
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
COMMON SHAREHOLDERS' EQUITY		
Common Stock-Par Value $6.50: (2003 / 2002)		
Shares Authorized. 600,000,000 600,000,000		
Shares Issued. 404,004,712 347,835,212		
(8,999,992 shares were held in treasury at September 30, 2003 and December 31, 2002)	2,626	2,261
Paid-in Capital	4,184	3,413
Accumulated Other Comprehensive Income (Loss)	(745)	(609)
Retained Earnings	2,393	1,999
TOTAL	8,458	7,064
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$36,079	$34,746

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in millions)	
OPERATING ACTIVITIES		
Net Income	$872	$318
Plus: Discontinued Operations	16	35
Income from Continuing Operations	888	353
Adjustments for Noncash Items:		
Depreciation and Amortization	984	1,066
Deferred Income Taxes	256	(81)
Deferred Investment Tax Credits	(24)	(21)
Cumulative Effect of Accounting Changes	(193)	350
Impairments	46	-
Amortization of Deferred Property Taxes	88	73
Amortization of Cook Plant Restart Costs	30	30
Mark to Market of Risk Management Contracts	(83)	217
Changes in Certain Current Assets and Liabilities:		
Accounts Receivable, net	176	(868)
Fuel, Materials and Supplies	(59)	(176)
Accrued Utility Revenues	70	(255)
Prepayments and Other	(37)	(387)
Accounts Payable	(400)	771
Taxes Accrued	(34)	126
Interest Accrued	30	107
Over/Under Fuel Recovery	131	(57)
Change in Other Assets	(224)	(373)
Change in Other Liabilities	(92)	(129)
Net Cash Flows From Operating Activities	1,553	746
INVESTING ACTIVITIES		
Construction Expenditures	(941)	(1,137)
Proceeds from Sale of Assets	49	1,116
Other	7	2
Net Cash Flows Used For Investing Activities	(885)	(19)
FINANCING ACTIVITIES		
Issuance of Common Stock	1,177	656
Issuance of Long-term Debt	4,146	1,819
Issuance of Equity Unit Senior Notes	-	334
Change in Short-term Debt, net	(2,825)	(806)
Retirement of Long-term Debt	(1,964)	(1,800)
Retirement of Preferred Stock	(2)	(10)
Retirement of Minority Interest	(225)	-
Dividends Paid on Common Stock	(480)	(590)
Net Cash Flows Used For Financing Activities	(173)	(397)
Effect of Exchange Rate Change on Cash	-	(3)
Net Increase in Cash and Cash Equivalents	495	327
Cash and Cash Equivalents at Beginning of Period	1,213	224
Cash and Cash Equivalents at End of Period	$1,708	$551
Net Decrease in Cash and Cash Equivalents from Discontinued Operations	$(1)	$(25)
Cash and Cash Equivalents from Discontinued Operations - Beginning of Period	8	108
Cash and Cash Equivalents from Discontinued Operations - End of Period	$7	$83

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SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $542 million and $555 million and for income taxes was $156 million and $242 million in 2003 and 2002, respectively. Noncash acquisitions under capital leases were $9 million in 2003 and $1 million in 2002.

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)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 2002	$2,153	$2,906	$3,296	$(126)	$8,229
Issuance of Common Stock	108	568			676
Common Stock Dividends			(590)		(590)
Other		(80)	15		(65)
TOTAL					8,250
COMPREHENSIVE INCOME (LOSS)					
Other Comprehensive Income (Loss), Net of Taxes:					
Foreign Currency Translation Adjustments				97	97
Unrealized Gains on Cash Flow Hedges				4	4
Unrealized Losses on Securities Available for Sale				(3)	(3)
NET INCOME			318		318
TOTAL COMPREHENSIVE INCOME					416
SEPTEMBER 30, 2002	$2,261	$3,394	$3,039	$ (28)	$8,666
JANUARY 1, 2003	$2,261	$3,413	$1,999	$(609)	$7,064
Issuance of Common Stock	365	812			1,177
Common Stock Dividends			(480)		(480)
Common Stock Expense		(36)			(36)
Other		(5)	2		(3)
TOTAL					7,722
COMPREHENSIVE INCOME (LOSS)					
Other Comprehensive Income (Loss), Net of Taxes:					
Foreign Currency Translation Adjustments				25	25
Unrealized Losses on Cash Flow Hedges				(177)	(177)
Unrealized Gains on Securities Available for Sale				1	1
Minimum Pension Liability				15	15
NET INCOME			872		872
TOTAL COMPREHENSIVE INCOME					736
SEPTEMBER 30, 2003	$2,626	$4,184	$2,393	$(745)	$8,458

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	----	----
	(in millions)	
TOTAL LONG-TERM DEBT OUTSTANDING		
First Mortgage Bonds	$1,247	$1,884
Installment Purchase Contracts	1,937	1,680
Notes Payable	323	520
Senior Unsecured Notes	8,171	4,819
Junior Debentures	-	205
Securitization Bonds	746	797
Notes Payable to Caddis	527	-
Notes Payable to Trust	321	-
Other Long-term Debt	358	247
Unamortized Discount (net)	(73)	(32)
	--------	-------
TOTAL	13,557	10,120
Less Portion Due Within One Year	1,234	1,633
	--------	-------
TOTAL LONG-TERM PORTION	$12,323	$8,487
	========	=======

1. GENERAL

The accompanying unaudited interim financial statements should be read in conjunction with the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) as incorporated in and filed with the Form 10-K/A.

Certain prior period financial statement items have been reclassified to conform to current period presentation. These items include the effects of discontinued operations, gains and losses associated with derivative trading contracts presented on a net basis in accordance with EITF 02-3, and counterparty netting in accordance with FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" and EITF Topic D-43, "Assurance That a Right of Setoff is Enforceable in a Bankruptcy under FASB Interpretation No. 39." Such reclassifications had no effect on previously reported Net Income. In addition, management determined that certain amounts were misclassified in AEP's 2002 Consolidated Statement of Operations resulting from errors in the coding of certain intercompany transactions and from transactions associated with our UK operations (see Note 30 in the Current Report on Form 8-K dated May 14, 2003). As a result, Gas Operations revenues increased by $41 million and decreased by $8 million and UK Operations and Other revenues increased by $2 million and decreased by $11 million for the three and nine month periods ended September 30, 2002, respectively. Fuel for Electric Generation decreased by $16 million and $60 million and Purchased Gas for Resale decreased by $51 million and $213 million for the three and nine month periods ended September 30, 2002, respectively. Expenses for Maintenance and Other Operation increased by $105 million and $235 million and Taxes Other Than Income Taxes increased by $5 million and $19 million for the three and nine month periods ended September 30, 2002, respectively. These revisions had no effect on Operating Income or Net Loss.

In the opinion of management, the unaudited interim financial statements reflect all normal recurring accruals and adjustments which are necessary for a fair presentation of the results of operations for interim periods.

2. SIGNIFICANT ACCOUNTING POLICIES

Accumulated Other Comprehensive Income

We expect to reclassify approximately $96 million of net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at September 30, 2003 to net income during the next twelve months at the time the hedged transactions affect net income. Seven years approximates the maximum period over which an exposure to a variability in future cash flows is hedged; less than 2% have a term longer than seven years. The actual amounts that we reclassify from Accumulated Other Comprehensive Income to Net Income can differ due to market price changes.

3. NEW ACCOUNTING PRONOUNCEMENTS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

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), 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 September 30, 2003). See Note 11 "Minority Interest in Finance Subsidiary" for further disclosures.

On July 1, 2003, we also deconsolidated the trusts which hold mandatorily redeemable trust preferred securities. Therefore, $321 million, previously reported as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries, is now reported as Notes Payable to Trust and is included in Long-term Debt.

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 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 Funding, LP (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 10 "Leases" for further disclosures.

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 the first quarter of 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 operating companies have recorded, in Accumulated Depreciation and Amortization, removal costs collected 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, from accumulated depreciation which resulted in a net favorable cumulative effect in the first quarter of 2003. However, we did not adjust the balance of such removal costs for our regulated operations, and in accordance with the present method of recovery, will continue to record such amounts through depreciation expense and accumulated depreciation. We estimate that we have approximately $1.2 billion of such regulatory liabilities recorded in Accumulated Depreciation and Amortization as of both September 30, 2003 and December 31, 2002.

The net favorable cumulative effect of the change in accounting principle for the nine months ended September 30, 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 (in millions):

	Nuclear Decommissioning	Ash Ponds	U.K. Plants, Wind Mills and Coal Operations	Total
Asset Retirement Obligation Liability at January 1, 2003	$718.3	$69.8	$37.2	$825.3
Accretion expense	39.1	4.2	1.6	44.9
Liabilities incurred	-	-	8.3	8.3
Foreign currency translation	-	-	3.5	3.5
Asset Retirement Obligation Liability at September 30, 2003	$757.4	$74.0	$50.6	$882.0

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

As of September 30, 2003 and December 31, 2002, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $800 million and $716 million, respectively, recorded in Other Assets on our Consolidated Balance Sheets.

Pro forma net income and earnings per share are not presented for the quarter ended September 30, 2002 or the years ended December 31, 2002, 2001 and 2000 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.

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 energy trading 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 energy trading transactions occurring on or after October 25, 2002. For physical inventory and non-derivative energy trading 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 after tax loss in net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in Cumulative Effect of Accounting Changes ($12 million in Utility Operations, $22 million in Investments - Gas Operations and $15 million in Investments - UK Operations segments).

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, 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 result of 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.

SFAS 150 requires that the following three types of freestanding financial instruments be reported as liabilities: (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) obligations that can be settled with shares, the monetary value of which is either (a) fixed, (b) tied to the value of a variable other than the issuer's shares, or (c) varies inversely with the value of the issuer's 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. Upon adoption of SFAS 150, any measurement change for these liabilities is to be reported as the cumulative effect of a change in accounting principle.

Beginning with our third quarter 2003 financial statements, $83 million of mandatorily redeemable Cumulative Preferred Stocks of Subsidiaries is now presented as Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption, a component of Non-Current Liabilities on the consolidated balance sheets. Beginning July 1, 2003, dividends on these mandatorily redeemable preferred shares are now classified as interest expense on the consolidated statements of operations. In accordance with SFAS 150, dividends from prior periods remain classified as preferred stock dividends (a component of Preferred Stock Dividend Requirements of Subsidiaries).

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.

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. This guidance is an interpretation of SFAS 5, 57 and 107 and a rescission of FIN 34. The initial recognition and initial measurement provisions of FIN 45 are effective on a prospective basis for guarantees issued or modified after December 31, 2002. The disclosure requirements of FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002. See Note 7 for further disclosures.

Future Accounting Changes

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.

4. RATE MATTERS

Fuel in SPP Area of Texas

As discussed in Note 6 of the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), 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. The PUCT has ruled that TNC fuel factors in the SPP area will be based upon the price-to-beat fuel factors offered by the REP in the ERCOT portion of TNC's service territory. 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 its SPP area. The adjustments removed $3.71 per MWH from reconcilable fuel expense. This adjustment will reduce revenues received from TNC's SPP customers by approximately $400,000 annually. These customers are now served by SWEPCo's REP.

TNC Fuel Reconciliation

In June 2002, TNC filed with the PUCT to reconcile fuel costs and 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 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. The under-recovery balance at December 31, 2001 for TNC's service within SPP was $0.7 million including interest. As noted above, TNC's SPP customers are now being served by SWEPCo's REP.

In March 2003, the Administrative Law Judges (ALJ) in this proceeding filed their Proposal for Decision (PFD). The PFD includes a recommendation that TNC's under-recovered retail fuel balance be reduced by approximately $12.5 million. In March 2003, TNC established a reserve of $13 million, including interest, based on the recommendations in the PFD. On April 22, 2003, TNC and intervenors in this proceeding filed exceptions to the PFD. On May 28, 2003, the PUCT remanded TNC's final fuel reconciliation to the ALJ to consider two issues. These remand issues could result in additional disallowances. The issues are the sharing of off-system sales margins from AEP's trading activities with customers through the fuel factor 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 is proposing that the sharing of off-system sales margins should continue beyond the termination of the fuel factor. 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. TNC made a filing on July 15, 2003 addressing the remand issues. Intervenors and the PUCT Staff filed statements of position or testimony in August 2003 and TNC filed rebuttal testimony in September 2003. The intervenors recommended $14.3 million of disallowances for the two remanded issues. On September 9, 2003, portions of TNC's testimony which related to the requirements of the AEP/CSW merger settlement to share off-system sales margins were stricken by the ALJ. The ALJ ruled that the requirement to share off-system sales margins had been determined by the PUCT and that the scope of the remand was only to determine the off-system sales margin sharing methodology. 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 and that after a thorough review of the evidence it is only reasonably possible that TNC will ultimately share margins after the end of the Texas fuel factor. Due to a provision established in the first quarter of 2003, the resolution of the fuel factor issue should have an immaterial impact on future results of operations, cash flows and financial condition. However, the ultimate decision could result in additional income reductions for these issues. It is presently expected that the ALJ's PFD and the PUCT's final decision regarding these remanded issues will occur in late 2003 or early 2004.

In February 2002, TNC received a final order from the PUCT in a 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 with the PUCT to reconcile fuel costs and to defer its over-recovery of fuel for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 1998 through December 2001 will be TCC's final fuel reconciliation. 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. Recommendations from intervening parties were received in April 2003 and hearings were held in May 2003. Intervening parties have recommended disallowances totaling $170 million. An ALJ report is expected in 2003 or the first quarter of 2004.

In March 2003, the ALJ hearing the TNC final fuel reconciliation, discussed above, issued a PFD in the TNC proceeding. Various issues addressed in TNC's proceeding may also be applicable to TCC's proceeding. Consequently, TCC established a reserve for potential adverse rulings of $27 million during the first quarter of 2003. Based upon the PUCT's remand of certain TNC issues, TCC established an additional reserve of $9 million in the second quarter of 2003. In July 2003, the ALJ requested that additional information be provided in the TCC fuel reconciliation related to the impact of the TNC remand order on TCC. Management believes, based on advice of counsel, that it is only reasonably possible that it will ultimately be determined that TCC should share off-system sales margins after the end of the Texas fuel factor. However, an adverse ruling 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 5 "Customer Choice and Industry Restructuring."

SWEPCo Texas Fuel Reconciliation

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs. This reconciliation covers the period of January 2000 through December 2002. At December 31, 2002, SWEPCo's filing detailed a $2.2 million over-recovery balance including interest. During the reconciliation period, SWEPCo incurred $434.8 million of eligible fuel expense. Any ruling by the PUCT preventing recovery of

SWEPCo's fuel costs could have a material impact on future results of operations, cash flows and financial condition. Intervenor and PUCT Staff recommendations will be filed in November 2003 and hearings are scheduled for January 2004.

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 Court remanded the cases to the PUCT for further proceedings consistent with its ruling. 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. Management appealed the District Court decisions to the Third Court of Appeals and 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

TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from an UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. The UCOS proceeding set the regulated wires rates to be effective when retail electric competition began. Regulated delivery charges include the retail transmission and distribution charge including a nuclear decommissioning fund charge and 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 the AEP REP (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 reducing the PTB rates for the period prior to the sale is approximately $11 million pre-tax. Management has appealed this decision and, based on advice of counsel, believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal, it could have an adverse effect on future results of operations and cash flows.

McAllen Rate Review

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 has a minimum of 120 days to provide support for its rates to the municipalities. TCC has the right to appeal any rate change by the municipalities to the PUCT. Pursuant to an agreement with the cities, TCC filed the requested support for its rates (test year ending June 30, 2003) with both the cities and the PUCT on November 3, 2003. TCC filed to decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%. 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. A procedural schedule has been developed requiring LPSC Staff and intervenor testimony be filed in January 2004. Management believes that SWEPCo's fuel costs prior to 1999 were proper and have been approved by the LPSC and that SWEPCo's historical fuel costs are reasonable. 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.

FERC Wholesale Fuel Complaints

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), 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 have resulted in new contracts. Consequently, an offer of settlement was filed at FERC in June 2003 regarding the fuel complaint and new contracts. Management is unable to predict whether FERC will approve this offer of settlement, but it is not expected to have a significant impact on TNC's financial condition. In March 2002, TNC recorded a provision for refund of $2.2 million before income taxes. TNC anticipates that the provision for refund will be adequate to cover the financial implications resulting from these new contracts. Should FERC fail to approve the settlement and new contracts, the actual refund and final resolution of this matter could differ materially from the provision and may have a negative impact on future results of operations, cash flows and financial condition.

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 Big Sandy Plant. See NOx Reductions in Note 6.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million was effective in May 2003 and an additional $16.2 million was 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 before August 1, 2003 (revised to October 31, 2003). In October 2003, PSO filed the required data for this case and requested an increase of $36 million annually, which is an 8.7% increase over existing base rates. A procedural schedule has not been set for this case. 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

As discussed in Note 6 of the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), PSO had a $44 million under-recovery of fuel costs resulting from a reallocation in 2002 of purchased power costs for periods prior to January 1, 2002. On July 23, 2003, PSO filed with the OCC seeking recovery of the $44 million over an eighteen-month time period. In August 2003, the OCC Staff filed testimony recommending recovery of $42.4 million ($44 million less two audit adjustments) over three years. In September 2003, the OCC expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. If the OCC does not permit recovery of the $42.4 million or determines, as a result of the review, that material fuel and purchased power cost 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 would be effective for 17 months and is estimated to reduce revenues by $36 million during that 17-month period. By order dated July 23, 2003, the Virginia SCC approved APCo's requested fuel factor reduction on an interim basis, subject to further investigation. No other parties to the proceeding have raised any issues with respect to APCo's request and the Virginia SCC Staff has filed testimony recommending that APCo's request be approved. 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. A hearing on this matter was held on November 5, 2003.

FERC Long-term Contracts

In September 2002, the FERC voted to hold hearings to consider requests from certain wholesale customers located in Nevada and Washington to break long-term contracts which they allege are "high-priced." At issue are long-term contracts entered into during the California energy price spike in 2000 and 2001. The complaints allege that AEP sold power at unjust and unreasonable prices. The FERC delayed hearings to allow the parties to hold settlement discussions. In January 2003, the FERC settlement judge indicated that the parties' settlement efforts were not progressing and he recommended that the complaint be placed back on the schedule for a hearing. 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 a similar complaint, a FERC administrative law judge (ALJ) ruled in favor of AEP and dismissed, in December 2002, a complaint filed by two Nevada utilities. In 2000 and 2001, we agreed to sell power to the utilities for future delivery. In late 2001, the utilities filed complaints 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 consummated. 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. At a hearing held in April 2003, the utilities asked FERC to void the long-term contracts. In June 2003, the FERC issued an order affirming the ALJ's decision and denying the utilities' complaint. The utilities requested a rehearing. In August 2003, the FERC granted the request for rehearing. Management is unable to predict the outcome of this proceeding or 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 $24 million of RTO formation and integration costs and related carrying charges through September 30, 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 the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO until after June 30, 2004 and only then with the approval of the Virginia SCC. 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 allowing us to submit additional evidence. A hearing date has not been scheduled.

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 ($2 million for I&M) before any deferral of the costs for future recovery. On September 30, 2003, AEP filed a petition for reconsideration of the IURC's order, asking the IURC to clarify that its discussion of the Alliance formation costs was not intended to cause an immediate write-off of the Indiana retail portion of these costs.

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 rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo. APCo's base rates are capped with no changes possible prior to 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 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 $23 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.

FERC Order on Regional Through and Out Rates

On July 23, 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 Regional Through and Out Rates (RTOR) on transactions where the energy is delivered within the Midwest ISO and PJM regions (RTO Footprint). In October 2003, the FERC postponed the November 1, 2003 deadline to eliminate RTOR. The elimination of the RTORs 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 RTORs. The FERC also found that the RTOR of some of the former Alliance RTO Companies, including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the Midwest ISO/PJM regions. FERC has initiated an investigation and hearing in regard to these rates. We made a filing with the FERC supporting the justness and reasonableness of our rates in August 2003 and made a joint filing with unaffiliated utilities, on October 14, 2003, proposing a regional revenue replacement mechanism for the lost revenues, in the event that FERC eliminates AEP's ability to collect RTOR in the RTO Footprint. Also on October 14, 2003, FERC issued an order delaying the November 1, 2003 elimination of RTORs without setting a new date for such elimination. The AEP East companies received approximately $150 million of RTOR 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 the ultimate outcome of this investigation, or its 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. 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. For the 2004 plan year, I&M was required to file a PSCR Plan case with the MPSC by September 30, 2003. 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.

5. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 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 in 2003 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 other applicable law by failing to participate in an RTO.

The complainants seek, among other relief, an order from the PUCO:
o suspending collection of transition charges by CSPCo and OPCo until transfer of control of their transmission assets has occurred

o 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

o 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 the FERC's reversal of its previous approval of our RTO filings and 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 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, or the outcome of these proceedings before the PUCO.

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.

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. The PUCO has circulated a draft of proposed rules but has not yet identified the method by which it will determine market rates for Default Service following the MDP.

As provided in stipulation agreements approved by the PUCO, we are deferring customer choice implementation 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. At September 30, 2003, we have incurred $65 million and deferred $25 million of such costs. Recovery of these regulatory assets will be subject to PUCO review in our next Ohio filings for new distribution rates. Approved rates will not become effective prior to 2009 for CSPCo and 2008 for OPCo. 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

On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in other areas of Texas including the SPP area in which SWEPCo operates. In May 2003, the PUCT approved a stipulation that delays competition in the SPP area until at least January 1, 2007.

A 2004 true-up proceeding will determine the amount and recovery of stranded plant costs as of December 31, 2001 including certain environmental costs incurred by May 1, 2003, final deferred fuel balance, net generation-related regulatory assets, unrefunded accumulated excess earnings, excess of price-to-beat revenues over market prices subject to certain conditions and limitations (Retail clawback), a true-up of the power costs used in the PUCT's ECOM model for 2002 and 2003 to reflect actual market prices determined through legislatively-mandated capacity auctions (wholesale capacity auction true-up) and other restructuring true-up issues.

The Texas Legislation provides for an earnings test each year from 1999 through 2001 and requires PUCT approval of the annual earnings test calculation. TCC, TNC and SWEPCo had appealed the PUCT's Final 2000 Earnings Test Order to the Texas Court of Appeals. In August 2003, the Appeals Court reversed the PUCT order and the district court judgment affirming it and remanded the controversy back to the PUCT for proceedings consistent with the Appeals Court's decision. The PUCT requested rehearing of the Court of Appeal's decision. Our 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 Final Orders, the companies reversed a portion of their regulatory liability and credited amortization expense during the third quarter of 2003. Pre-tax amounts by company were $5.1 million for TCC, $2.6 million for TNC and $1.1 million for SWEPCo.

The Texas Legislation provides for the affiliated PTB REP to refund to its transmission and distribution (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. The retail clawback regulatory liability is to be included in the 2004 true-up proceedings and netted against other true-up adjustments. If 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. In July 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. On August 21, 2003, the PUCT dismissed these filings and ruled that TCC and TNC should refile no sooner than September 22, 2003 in order to establish the required notice period. TCC and TNC refiled in late September 2003. In October 2003, the PUCT Staff recommended approval of TCC's application and denial of TNC's application. The PUCT Staff determined that only 39.9% of TNC's small commercial customers were served by competitive REPs as of the end of August 2003. If the PUCT denies TNC's application, TNC will likely meet the 40% threshold in September 2003 and refile its application. AEP had accrued a regulatory liability of approximately $9 million for the small commercial retail clawback on its REP's books. If the PUCT certifies that TCC and/or TNC have reached the 40% threshold, the regulatory liability would no longer be required for the small commercial class and could be reversed.

The Texas Legislation allows for several alternative methods to be used to value stranded generation assets in the 2004 true-up proceeding including the sale or exchange of generation assets, stock valuation methods or the use of an ECOM model for nuclear generation assets. TCC is the only AEP subsidiary that has stranded costs under the Texas Legislation.

In the fourth quarter of 2002, TCC decided to determine the market value of its generating assets through the sale of those assets for purposes of determining stranded costs for the 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. 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. The filing included a request for the PUCT to issue a declaratory order that TCC's 25.2% ownership interest in its nuclear plant, STP, can be sold to establish its market value for determining stranded plant costs. Intervenors to this proceeding, including the PUCT Staff, made filings to dismiss TCC's filing claiming that the PUCT does not have the authority to issue such a declaratory order. The intervenors also argued that the proper time to address the sales process is after the plants are sold during the 2004 true-up proceeding. Since the closing process for the plants sold is not expected to be completed before mid-2004, TCC requested that its 2004 true-up proceeding be scheduled after completion of the divestiture of its generating assets.

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. The PUCT dismissed TCC's request to certify its proposed divestiture plan; therefore its divestiture plan will be subject to a review in the 2004 true-up proceeding. The PUCT adopted a rule 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.

Texas Legislation also requires that electric utilities and their affiliated power generation companies (PGC) sell at auction in 2002 and 2003 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 replace the PUCT's earlier estimates of those market prices for 2002 and 2003 used in the ECOM model to calculate the wholesale capacity auction true-up adjustment for TCC for the 2004 true-up proceeding.

The decision to determine stranded costs by selling TCC's generating plants and the expectation that the sales price would produce a significant loss/stranded cost instead of using the PUCT's ECOM model negative stranded cost estimate, enabled TCC to record in 2002 a $262 million regulatory asset and related revenues which represents the quantifiable amount of the wholesale capacity auction true-up for the year 2002. Through September 30, 2003, TCC recorded an additional $169 million regulatory asset and related revenues for wholesale capacity auction true-up. Prior to the decision to pursue a sale of TCC's generating assets, the PUCT's negative ECOM estimate prohibited the recognition of the regulatory assets and revenues, as they cannot be recovered unless there are 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 plant costs.

In July 2003, the PUCT Staff published their proposed filing package for the 2004 true-up proceeding. Within the filing package are instructions and sample schedules that demonstrate the calculation of the wholesale capacity auction true-up. That calculation differs from the methodology being employed by TCC. TCC filed comments on the proposed 2004 true-up filing package in September 2003 and took exception to the methodology employed by the PUCT Staff. A true-up filing package will probably be approved by the PUCT in the fourth quarter of 2003. If the PUCT Staff's methodology is approved, TCC's wholesale capacity auction true-up regulatory asset could require adjustment.

In October 2003, a coalition of consumer groups (the Coalition of Ratepayers) including the Office of Public Utility Counsel, the State of Texas, Cities served by CPL and Texas Industrial Energy Consumers filed a petition with the PUCT requesting that the PUCT initiate a rulemaking to amend the PUCT's stranded cost true-up rule (True-up Rule). The Coalition of Ratepayers proposed to amend the True-up Rule to revise the calculation of the wholesale capacity auction true-up. If adopted, the Coalition of Ratepayers' proposal would substantially reduce or possibly eliminate the wholesale capacity auction true-up regulatory asset that TCC has accrued in 2002 and 2003. The PUCT has requested that responses to the Coalition of Ratepayers' petition be filed by November 7, 2003. On November 5, 2003, the PUCT denied the Coalition of Ratepayers' petition.

When the plant divestitures and the 2004 true-up proceeding are completed, TCC will file to recover PUCT-approved stranded costs and other true-up amounts that are in excess of current securitized amounts plus a carrying charge through a non-bypassable competition transition charge in rates of the regulated T&D utility. In addition, TCC may seek to securitize certain of the approved stranded plant costs and regulatory assets, 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 generation-related regulatory assets, unrecovered fuel balances, stranded plant costs, 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.

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.

6. COMMITMENTS AND CONTINGENCIES

Power Generation Facility

AEP has agreements with Juniper Capital L.P. (Juniper) under which Juniper will develop, construct, and finance a power generation facility (Facility) near Plaquemine, Louisiana and lease the Facility to AEP. Construction of the Facility was begun by Katco Funding, Limited Partnership (Katco), an unrelated unconsolidated special purpose entity, and Katco assigned its interest in the Facility to Juniper in June 2003. Juniper is a limited partnership, unaffiliated and unconsolidated with AEP, 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 has arranged to finance the Facility with debt financing up to $494 million and equity up to $31 million (approximately 6%) of the Facility's acquisition cost 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. The lease will be treated as an operating lease for financial accounting purposes. Consequently, the Facility and the related obligations are not reported on AEP's Consolidated Balance Sheet. Payments under the operating lease are expected to commence in the first quarter of 2004. AEP will in turn sublease the Facility to Dow Chemical Company (DOW). The use of Juniper allows AEP to limit its risk associated with the Facility once construction has been completed. In addition, the lease allows AEP to utilize certain tax benefits associated with the Facility.

In the event the project is terminated before completion of construction, AEP has 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.)

DOW will use a portion of the energy produced by the Facility and sell the excess energy. AEP has agreed to purchase approximately 800 MW of such excess energy from DOW. AEP has also agreed to sell 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, 2002 (PPA) at a price which is currently in excess of market. Beginning May 1, 2003, AEP was obligated pursuant to the PPA to provide replacement capacity, energy and ancillary services to TEM. TEM has rejected as non-conforming the replacement capacity, energy and ancillary services tendered by AEP.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United State District Court for the Southern District of New York. Both suits seek a declaration from the Court of the parties' respective rights under the PPA. AEP alleges that TEM has breached the PPA. TEM alleges that the PPA is unenforceable or alternatively, that AEP has breached the PPA. If the PPA is terminated or found to be unenforceable, AEP could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms including comparable levels of profitability.

AEP is the construction agent for Juniper. Construction is currently scheduled to be completed by the first quarter of 2004. If the Facility is not completed by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately $17.5 million.

The initial term of the operating lease between Juniper and AEP commences on the commercial operation date (COD) of the Facility and continues for five years or, if earlier, until June 2009. The lease contains extension options and if all extension options were exercised, the total term of the lease would 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. AEP has 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, AEP may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if AEP has 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 AEP's contract to purchase energy from DOW. If the lease were renewed for up to a 30-year lease term, AEP may renew the lease at fair market value subject to Juniper's approval, purchase the Facility at its original construction 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 AEP would not be required to make any payment if AEP has made the additional rental prepayment described below. AEP has guaranteed the performance of its subsidiaries to Juniper during the lease term. Due to FIN 45, at COD, AEP will be required to record the fair value (approximately $35 million) of this guarantee as a liability with an offsetting asset.

As of September 30, 2003, Juniper's acquisition costs for the Facility totaled $460 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 this operating lease will also increase. Annual payments of approximately $18 million represent future minimum payments during the initial term calculated using the indexed LIBOR rate (1.14% at September 30, 2003). An additional rental prepayment (up to $396 million as of September 30, 2003) may be due on June 30, 2004 unless Juniper has refinanced its present debt financing on a long-term basis. The Facility is collateral for the debt obligation of Juniper. Our maximum exposure to loss as a result of our financing transaction with Juniper is 89.9% of Juniper's project costs during the construction phase and up to $396 million once the construction is completed. These calculations could change based on the final amount of total costs or changes in interest rates. Maximum loss is deemed to be remote due to the collateralization.

As a result of Katco's transfer of its interest in the Facility to Juniper, we did not consolidate Juniper or any portion of the Facility in accordance with FIN 46.

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. 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.

Federal EPA Complaint and Notice of Violation

As discussed in Note 9 of the Combined Notes to Financial Statements in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), AEPSC, APCo, CSPCo, I&M, and OPCo are involved in litigation regarding generating plant emissions under the Clean Air Act. The Federal EPA and a number of states alleged APCo, CSPCo, I&M, OPCo and eleven unaffiliated utilities modified certain units at coal-fired generating plants in violation of the Clean Air Act. The Federal EPA filed complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20-year period.

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 April 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.

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 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.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the Clear Air Act proceedings and is 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. In the event that 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.

NOx Reductions

The Federal EPA issued a NOx Rule requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. The NOx Rule has been upheld on appeal. The compliance date for the NOx Rule is May 31, 2004.

In 2000, the Federal EPA also adopted a revised rule (the Section 126 Rule) granting petitions filed by certain northeastern states under the Clean Air Act. The rule imposes emissions reduction requirements comparable to the NOx Rule beginning May 1, 2003, for most of our coal-fired generating units. Affected utilities, including certain AEP operating companies, petitioned the D.C. Circuit Court to review the
Section 126 Rule.

After review, the D.C. Circuit Court instructed the Federal EPA to justify the methods it used to allocate allowances and project growth for both the NOx Rule and the Section 126 Rule. AEP subsidiaries and other utilities requested that the D.C. Circuit Court vacate the Section 126 Rule or suspend its May 2003 compliance date. In 2001, the D.C. Circuit Court issued an order tolling the compliance schedule until the Federal EPA responds to the Court's remand. On April 30, 2002, the Federal EPA announced that May 31, 2004 is the compliance date for the
Section 126 Rule. The Federal EPA published a notice in the Federal Register on May 1, 2002 advising that no changes in the growth factors used to set the NOx budgets were warranted. In June 2002, our subsidiaries joined other utilities and industrial organizations in seeking a review of the Federal EPA's actions in the D.C. Circuit Court. This action is pending.

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 reduce NOx emissions to comply with the applicable state and Federal NOx requirements. This includes selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units. During 2001, 2002 and 2003, SCR technology commenced operations on units of Gavin, Amos, Mountaineer, Big Sandy and Cardinal plants. Construction of SCR technology at certain other AEP generating units continues. Other combustion control technologies have been installed and commenced operation on a number of units across the AEP System and additional units will be equipped with these technologies.

Our NOx compliance plan is a dynamic plan that is continually reviewed and revised as new information becomes available on the performance of installed technologies and the cost of planned technologies. Certain compliance steps may or may not be necessary as a result of this new information. Consequently, the plan has a range of possible outcomes. Current estimates indicate that our compliance with the NOx Rule, the Texas Commission on Environmental Quality rule and the Section 126 Rule could result in required capital expenditures in the range of $1.3 billion to $1.7 billion, of which $1 billion has been spent through September 30, 2003. Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than these estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs for additional pollution control equipment are recovered from customers, these costs would adversely affect future results of operations, cash flows and possibly financial condition.

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 preliminary 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 are unable to predict whether these discussions will lead to an agreement on these subjects. If these discussions do not lead to an agreement, Enron may attempt to reject certain of the agreements relating to the Bammel storage facility and certain appurtenant pipelines.

We also entered into an agreement with BAM Lease Company which grants HPL the right to use approximately 65 billion cubic feet of cushion gas (or pad gas) required for the normal operation of the Bammel gas storage facility. The Bammel Gas Trust, which purportedly owned approximately 55 billion cubic feet of gas, had entered into a financing arrangement in 1997 with Enron and a group of banks. These banks purported to have certain rights to gas in certain events of default. In connection with our acquisition of HPL, the banks entered into an agreement granting HPL's exclusive use of the 65 billion cubic feet of cushion gas and released HPL from liabilities and obligations under the financing arrangement. HPL was thereafter informed by the banks of a purported default by Enron under the terms of the referenced 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 gas from the storage facility. In September 2002, HPL filed a general denial and certain counterclaims against the banks. HPL also filed a motion to dismiss, which was denied. Trial is currently scheduled for December 2003. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows and financial condition.

On October 31, 2003, AEP Energy Services Gas Holding Company filed a lawsuit against Bank of America in the United States District Court for the Southern District of Texas. The lawsuit seeks damages for Bank of America's breach of contract and negligent misrepresentation in connection with transactions surrounding our acquisition of HPL from Enron. Bank of America led a lending syndicate involved in financing transactions that Enron and its subsidiaries undertook, including transactions that were prior to the sale of HPL and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that we purchased HPL and undertook other related actions based on representations that Bank of America made about Enron's financial condition that Bank of America knew or should have known were false.

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.

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. 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.

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. 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. The case is pending on plaintiff's motion to remand the case to state court. 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 intend to vigorously defend against these actions.

California Lawsuit

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.

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.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, has filed a lawsuit in federal District Court in Corpus Christi, Texas 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. This case is in the initial pleading stage. We have filed a Motion to Dismiss. The Court has set a hearing on the Motion to Dismiss for January 2004. Management believes that the claims against us are without merit. We intend to vigorously defend against the claims.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals and claimed approximately $34 million was owed to BOM by AEP. 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 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 approximately $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

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), 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.

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. Although management is unable to predict the outcome of this case, it is not expected to have a material effect on results of operations or cash flows.

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 FERC received on its proposal. Until the rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Proposed Security Standards

As part of the SMD proposed rulemaking, in July 2002, FERC published for comment proposed security standards. These standards were intended to ensure that all market participants would have a basic security program that would effectively protect the electric grid and related market activities. As proposed, these standards would apply to AEP's power transmission systems, distribution systems and related areas of business. The proposed standards have not been adopted. Subsequently, in 2002, the North American Electric Reliability Council (NERC), with FERC's support, developed a new set of standards to address industry compliance. These new standards closely parallel the initial, proposed FERC standards in both content and compliance time frames, and were approved by the NERC ballot body in June 2003. We have developed financial requirements for security implementation and compliance with these NERC standards, the costs of which are not expected to be material to our future results of operations and cash flows.

7. GUARANTEES

There are no liabilities recorded for guarantees entered into prior to December 31, 2002 in accordance with FIN 45. There are certain liabilities recorded for guarantees entered into subsequent to December 31, 2002. These liabilities are immaterial to AEP. 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

AEP and certain of its subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity trading contracts, construction contracts, insurance programs, security deposits, debt service reserves, drilling funds and credit enhancements for issued bonds. All of these LOCs were issued by AEP or a subsidiary in the ordinary course of business. At September 30, 2003, the maximum future payments for all the LOCs are approximately $181 million with maturities ranging from September 30, 2003 to January 2011. Included in these amounts is TCC's LOC of approximately $40.9 million with a maturity date of November 2003. 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.

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 $3.7 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 $4.7 million, which expires July 2010.

AEP

AEP has guaranteed 50% of the principal and interest payments as well as 50% of a Power Purchase Agreement (PPA) of Fort Lupton, an IPP of which AEP is a 50% owner. In the event Fort Lupton does not make the required debt payments, AEP has a maximum future payment exposure of approximately $6 million, which expires May 2008. In the event Fort Lupton is unable to perform under its PPA agreement, AEP has a maximum future payment exposure of approximately $14.8 million, which expires June 2019.

AEP has 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 AEP is a 50% owner. In the event Orange fails to make payments in accordance with agreements for gas transmission, AEP has a maximum future payment exposure of approximately $0.8 million, which expires June 2023. In the event Orange is unable to perform under its PPA agreement, AEP has a maximum future payment exposure of approximately $1.1 million, which expires June 2016.

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 a revolving credit agreement, 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 $60 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 September 30, 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 3). 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 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.

Other

See Power Generation Facility section of Note 6 "Commitments and Contingencies" for disclosure of related guarantees.

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 the first nine months of 2003, we entered into several sale agreements discussed in Note 8. These sale agreements include indemnifications with a maximum exposure of approximately $67 million. There are no material liabilities recorded for any indemnifications entered into during the first nine months of 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 September 30, 2003, the maximum potential loss for these lease agreements was approximately $27 million assuming the fair market value of the equipment is zero at the end of the lease term.

See Note 10 "Leases" for disclosure of lease residual value guarantees.

8. DISPOSITIONS, DISCONTINUED OPERATIONS, ASSETS HELD FOR SALE AND IMPAIRMENTS

DISPOSITIONS

Dispositions During the First Half of 2003

During the first six months of 2003, we completed the sales of C3 Communications, Mutual Energy Service Company, LLC, our Newgulf facility, our Nordic Trading business, our water heater rental program assets and our interest in AEP Gas Power Systems, LLC. The impact on our results of operations for the third quarter and for the nine months ended September 30, 2003 was not significant.

Eastex

We completed the sale of Eastex during the third quarter of 2003. We provided for a $218.7 million pre-tax asset impairment in the fourth quarter 2002, 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. 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. The balance sheet components consisted of Current Assets of $15 million, Current Liabilities of $8 million and Other Liabilities of $4 million.

DISCONTINUED OPERATIONS

The results of operations of the entities shown below, affecting AEP, have been reclassified as Discontinued Operations for all periods presented. The assets and liabilities of Pushan Power Plant were aggregated on our Consolidated Balance Sheets as Assets Held for Sale and Liabilities Held for Sale (see table at the end of the Assets Held for Sale section below for more detailed information):

For the quarter ended September 30, 2003 and 2002:

	SEEBOARD	CitiPower	Pushan Power Plant	Eastex	Total
			(in millions)		
2003 Revenue	$-	$-	$14	$12	$26
2002 Revenue	-	(2)	18	22	38
2003 Earnings (Loss) After Tax	$-	$-	$-	$-	$-
2002 Earnings (Loss) After Tax	46	(8)	4	(3)	39

For the nine months ended September 30, 2003 and 2002:

	SEEBOARD	CitiPower	Pushan Power Plant	Eastex	Total
			(in millions)		
2003 Revenue	$-	$-	$41	$58	$99
2002 Revenue	694	204	44	50	992
2003 Earnings (Loss) After Tax	$-	$-	$(1)	$(15)	$(16)
2002 Earnings (Loss) After Tax	82	(116)	7	(8)	(35)

ASSETS HELD FOR SALE

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), during 2002, we recorded an estimated loss on disposal of assets held for sale. The following provides an update of those assets still held for sale.

Pushan Power Plant

We currently anticipate that negotiations to sell our interest in the Pushan Power Plant (Pushan) in Nanyang, China to one of the minority interest partners will be completed by the second quarter of 2004. This anticipated closing date is later than originally expected due to several unusual circumstances including the SARS outbreak and governmental and regulatory delays. Results of operations of Pushan have been reclassified as Discontinued Operations in accordance with SFAS 144. The assets and liabilities of Pushan have been reclassified on our Consolidated Balance Sheets as Assets Held for Sale and Liabilities Held for Sale. See the tables at the end of this section for more detailed information.

Excess Equipment

In November 2002, as a result of a cancelled development project, we obtained title to a surplus gas turbine generator. We anticipate the sale of the turbine before the end of 2003. The Other Assets have been reclassified on our Consolidated Balance Sheets as Assets Held for Sale. See the tables at the end of this section for more detailed information.

Excess Real Estate

In the fourth quarter of 2002, we began to market an under-utilized office building in Dallas, TX obtained through the merger with CSW. We currently anticipate the sale of the facility to be completed by the end of 2003. The property asset has been reclassified on our Consolidated Balance Sheets as Assets Held for Sale. See the tables at the end of this section for more detailed information.

The assets and liabilities of the entities held for sale at September 30, 2003 and December 31, 2002 are as follows:

September 30, 2003	Pushan Power Plant	Excess Real Estate	Excess Equipment	Total
	(in millions)			
Assets:				
Current Assets	$20	$-	$-	$20
Property, Plant and Equipment, Net	144	18	-	162
Other Assets	-	-	12	12
Total Assets Held for Sale	$164	$18	$12	$194
Liabilities:				
Current Liabilities	$26	$-	$-	$26
Long-term Debt	20	-	-	20
Other Liabilities	52	-	-	52
Total Liabilities Held for Sale	$98	$-	$-	$98

Pushan Power Plant	Newgulf Facility	Nordic Trading	Excess Real Estate	Excess Equipment	Water Heater Program	Tele-communications	Total

December 31, 2002					(in millions)			
Assets:								
Current Assets	$19	$-	$35	$-	$-	$1	$-	$55
Property, Plant and Equipment, Net	132	6	-	18	-	38	6	200
Other Assets	-	-	10	-	12	-	-	22
Total Assets Held for Sale	$151	$6	$45	$18	$12	$39	$6	$277
Liabilities:								
Current Liabilities	$28	$-	$48	$-	$-	$-	$-	$76
Long-term Debt	25	-	-	-	-	-	-	25
Other Liabilities	26	-	3	-	-	-	-	29
Total Liabilities Held for Sale	$79	$-	$51	$-	$-	$-	$-	$130

IMPAIRMENTS

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 studies of recent market conditions and assumptions, 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) charge was recorded in September 2003 as a result of the other than temporary impairment of the equity interest under APB 18. This loss of investment value is included in Investment Value and Other Impairment Losses on our Consolidated Statements of Operations. These equity investments are included in our "Investments - Other" business segment.

9. BUSINESS SEGMENTS

Our segments and their related business activities are as follows:

Utility Operations
o Domestic generation of electricity for sale to retail and wholesale customers
o Domestic electricity transmission and distribution
o Parent company, which includes corporate related expenditures, interest income and interest expense

Investments - Gas Operations
o Gas pipeline and storage services

Investments - UK Operations
o International generation of electricity for sale to wholesale customers

Investments - Other
o Coal mining, bulk commodity barging operations and other energy supply businesses

The tables below present segment information for the nine months ended September 30, 2003 and 2002 and the three months ended September 30, 2003 and 2002. These amounts include certain estimates and allocations where necessary.

		Investments				
	Utility Operations	Gas Operations	UK Operations	Other	Reconciling Adjustments	Consolidated
Nine Months Ended September 30, 2003			(in millions)			
Revenues from:						
External Customers	$8,512	$2,791	$116	$439	$ -	$11,858

	Utility Operations	Gas Operations	UK Operations	Other	Reconciling Adjustments	Consolidated
Other Operating Segments	15	255	-	74	(344)	-
Discontinued Operations	-	-	-	(16)	-	(16)
Cumulative Effect of Accounting Changes, net of tax	237	(22)	(22)	-	-	193
Net Income (Loss)	1,123	(81)	(110)	(60)	-	872
Total Assets	29,262	3,062	1,847	1,714	194 (a)	36,079
Gross Property Additions	916	10	9	6	-	941

		Investments				
	Utility Operations	Gas Operations	UK Operations	Other	Reconciling Adjustments	Consolidated
Nine Months Ended September 30, 2002			(in millions)			
Revenues from:						
External Customers	$7,858	$1,803	$187	$536	$ -	$10,384
Other Operating Segments	-	192	-	120	(312)	-
Discontinued Operations	-	-	-	(35)	-	(35)
Cumulative Effect of Accounting Changes, net of tax	-	-	-	(350)	-	(350)
Net Income (Loss)	846	(75)	6	(459)	-	318
Total Assets	26,700	4,857	1,644	2,350	814(a)	36,365
Gross Property Additions	942	33	31	131	-	1,137

		Investments				
	Utility Operations	Gas Operations	UK Operations	Other	Reconciling Adjustments	Consolidated
Three Months Ended September 30, 2003			(in millions)			
Revenues from:						
External Customers	$3,111	$860	$4	$134	$-	$4,109
Other Operating Segments	15	155	-	46	(216)	-
Discontinued Operations	-	-	-	-	-	-
Cumulative Effect of Accounting Changes, net of tax	-	-	-	-	-	-
Net Income (Loss)	372	(20)	(51)	(44)	-	257
Total Assets	29,262	3,062	1,847	1,714	194(a)	36,079
Gross Property Additions	289	-	-	3	-	292

		Investments				
	Utility Operations	Gas Operations	UK Operations	Other	Reconciling Adjustments	Consolidated
Three Months Ended September 30, 2002			(in millions)			
Revenues from:						
External Customers	$2,940	$700	$53	$118	$-	$3,811
Other Operating Segments	-	58	-	42	(100)	-
Discontinued Operations	-	-	-	39	-	39
Cumulative Effect of Accounting Changes, net of tax	-	-	-	-	-	-
Net Income (Loss)	405	5	(5)	20	-	425
Total Assets	26,700	4,857	1,644	2,350	814(a)	36,365
Gross Property Additions	311	17	11	14	-	353

(a) Reconciling adjustments for Total Assets include Assets Held for Sale and/or Assets of Discontinued Operations.

10. LEASES

OPCo has entered into an agreement with JMG Funding LLP (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. The lease is accounted for as an operating lease. Payments under the operating lease 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.

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.

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. 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. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.

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 cost evenly over the expected twenty-year usage period. In addition, the lease allows us to take the income tax benefits otherwise associated with ownership.

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 September 30, 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.

11. MINORITY INTEREST IN FINANCE SUBSIDIARY

Due to the application of FIN 46, we deconsolidated Caddis Partners, LLC (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 Notes Payable to Caddis, a component of Long-Term Debt ($527 million at September 30, 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.

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

On May 9, 2003, SubOne borrowed $225 million from AEP 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 and the stock price trigger.

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 September 30, 2003, SubOne has complied with the covenants contained in the credit agreement. In addition, the acceleration of AEP and certain subsidiaries' debt outstanding, in excess of $50 million, is an event of default under the credit agreement.

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 AEP's 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 AEP.

SubOne has deposited $414 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 AEP guaranteed the repayment obligations of these affiliates. These loans must be repaid in the event AEP's credit ratings fall below investment grade.

12. FINANCING AND RELATED ACTIVITIES

Long-term debt and other securities issuances and retirements during the first nine months of 2003 were:

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Issuances:				
AEP	Senior Unsecured Notes	$500	5.375	2010
AEP	Senior Unsecured Notes	300	5.25	2015
AEP	Other Debt	2	Variable	2005
APCo	Senior Unsecured Notes	200	3.60	2008
APCo	Senior Unsecured Notes	200	5.95	2033
APCo	Installment Purchase Contracts	100	5.50	2022
CSPCo	Senior Unsecured Notes	250	5.50	2013
CSPCo	Senior Unsecured Notes	250	6.60	2033
KPCo	Senior Unsecured Notes	75	5.625	2032
OPCo	Senior Unsecured Notes	250	5.50	2013
OPCo	Senior Unsecured Notes	250	6.60	2033
OPCo	Senior Unsecured Notes	225	4.85	2014
OPCo	Senior Unsecured Notes	225	6.375	2033
PSO	Senior Unsecured Notes	150	4.85	2010
SWEPCo	Senior Unsecured Notes	100	5.375	2015
SWEPCo	Secured Note of Subsidiary	44	4.47	2011
TCC	Senior Unsecured Notes	150	3.00	2005
TCC	Senior Unsecured Notes	100	Variable	2005
TCC	Senior Unsecured Notes	275	5.50	2013
TCC	Senior Unsecured Notes	275	6.65	2033
TNC	Senior Unsecured Notes	225	5.50	2013

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date

Retirements:

AEP	Bank Facility	$1,300	Variable	2003
AEP	Senior Unsecured Notes	49	6.125	2006
AEP	Senior Unsecured Notes	250	5.50	2003
AEP	Other Debt	9	Variable	2005
APCo	First Mortgage Bonds	70	8.50	2022
APCo	First Mortgage Bonds	30	7.80	2023
APCo	First Mortgage Bonds	20	7.15	2023
APCo	Installment Purchase Contracts	10	7.875	2013
APCo	Installment Purchase Contracts	40	6.85	2022
APCo	Installment Purchase Contracts	50	6.60	2022
APCo	Senior Unsecured Notes	100	7.20	2038
APCo	Senior Unsecured Notes	100	7.30	2038
APCo	Senior Unsecured Notes	125	Variable	2003
CSPCo	First Mortgage Bonds	2	8.70	2022
CSPCo	First Mortgage Bonds	15	8.55	2022
CSPCo	First Mortgage Bonds	14	8.40	2022
CSPCo	First Mortgage Bonds	13	8.40	2022
CSPCo	First Mortgage Bonds	13	6.80	2003
CSPCo	First Mortgage Bonds	26	6.55	2004
CSPCo	First Mortgage Bonds	26	6.75	2004
CSPCo	First Mortgage Bonds	40	7.90	2023
CSPCo	First Mortgage Bonds	33	7.75	2023
CSPCo	First Mortgage Bonds	25	6.60	2003
I&M	First Mortgage Bonds	75	8.50	2022
I&M	First Mortgage Bonds	15	7.35	2023
I&M	Junior Debentures	40	8.00	2026
I&M	Junior Debentures	125	7.60	2038
KPCo	Junior Debentures	40	8.72	2025
OPCo	First Mortgage Bonds	30	6.75	2003
PSO	First Mortgage Bonds	35	6.25	2003
PSO	First Mortgage Bonds	65	7.25	2003
SWEPCo	First Mortgage Bonds	55	6.625	2003
SWEPCo	Secured Note of Subsidiary	2	4.47	2011
SWEPCo	Notes Payable	1	Variable	2008
TCC	First Mortgage Bonds	18	7.50	2023
TCC	First Mortgage Bonds	16	6.875	2003
TCC	Securitization Bonds	51	3.54	2005
Non-Registrant:				
AEP Subsidiary	Notes Payable	7	6.225	2017
AEP Subsidiary	Revolving Credit Agreement	306	Variable	2003
AEP Subsidiary	Senior Unsecured Notes	17	6.50	2003
AEP Subsidiary	Other Debt	6	Variable	2007

In addition to the transactions reported in the table above, the following table lists intercompany issuances and retirements of debt due to AEP:

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	

Issuance:

Non-Registrant				
AEP Subsidiary	Notes Payable	$225	5.57	2010
Retirements:				
CSPCo	Notes Payable	$160	6.501	2006
KPCo	Notes Payable	15	4.336	2003
OPCo	Notes Payable	240	6.501	2006
OPCo	Notes Payable	60	4.336	2003
Non-Registrant:				
AEP Subsidiaries	Notes Payable	105	4.336	2003
AEP Subsidiary	Notes Payable	12	6.501	2006

Other Matters

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, we 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.

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 new sale of receivables agreement, which expires on July 23, 2004, provides commitments of $600 million to purchase receivables from AEP Credit. At September 30, 2003, $529 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, AEP 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.

Common Stock

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 $1,141 million (net of issuance costs of $36 million). Proceeds from the sale of common stock were used to pay down both short-term and long-term debt with the balance being held in cash.

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

AEGCo is engaged in the generation and wholesale sale of electric power to two affiliates under long-term agreements. Operating revenues are derived from the sale of Rockport Plant energy and capacity to two affiliated companies pursuant to FERC approved long-term unit power agreements. The unit power agreements provide for a FERC approved rate of return on common equity (12.16% annually), a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes.

Results of Operations

Net Income increased $74 thousand during the third quarter of 2003 compared with the third quarter of 2002 and increased $27 thousand in the nine-month period ended September 30, 2003 compared with the nine-month period ended September 30, 2002. The fluctuations in Net Income are a result of terms in the unit power agreements which limit recovery of return on capital related to operating and in-service ratios of the Rockport Plant calculated and adjusted monthly.

Third Quarter 2003 Compared to Third Quarter 2002
Operating Income

Operating Income increased $373 thousand for the third quarter primarily due to the following:

o Operating Revenue increased as a result of increased recoverable expenses, primarily Other Operation and Maintenance, in accordance with the unit power agreements.

The increase in Operating Income was partially offset by the following:

o Fuel for Electric Generation expense increased primarily due to an increase in the average cost of coal.
o Other Operation and Maintenance increased in the current quarter due to a planned maintenance outage in September 2003.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Operating Income

Operating Income increased $467 thousand year-to-date primarily due to the following:

o Operating Revenue increased as a result of increased recoverable expenses, primarily fuel, as net generation increased 15% year-to-date.
o Other Operation and Maintenance decreased year-to-date due to higher costs incurred for planned maintenance outages in the first quarter of 2002.
o The decrease in Taxes Other Than Income Taxes year-to-date reflects a decline in the accrual of Indiana's real and personal property taxes for the Rockport Plant, reflecting a favorable change in the tax law effective March 2002.

The increase in Operating Income was partially offset by the following:

o Fuel for Electric Generation expense increased primarily due to increased generation and an increase in the average cost of coal.
o Income Taxes attributable to operations increased due to an increase in pre-tax operating book income.

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2003	2002	2003	2002
	(in thousands)			
OPERATING REVENUES	$59,008	$55,988	$179,004	$159,219
OPERATING EXPENSES				
Fuel for Electric Generation	27,514	26,702	87,148	65,737
Rent - Rockport Plant Unit 2	17,071	17,071	51,212	51,212
Other Operation	2,691	2,023	7,683	9,259
Maintenance	2,461	1,484	6,399	6,838
Depreciation	5,695	5,643	16,981	16,918
Taxes Other Than Income Taxes	1,085	1,150	2,480	3,110
Income Taxes	682	479	1,927	1,438
TOTAL	57,199	54,552	173,830	154,512
OPERATING INCOME	1,809	1,436	5,174	4,707
Nonoperating Income	3	74	24	108
Nonoperating Expenses (Credits)	44	(8)	286	98
Nonoperating Income Tax Credits	878	886	2,617	2,541
Interest Charges	625	457	1,944	1,700
NET INCOME	$2,021	$1,947	$5,585	$5,558

STATEMENTS OF RETAINED EARNINGS
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2003	2002	2003	2002
	(in thousands)			
BALANCE AT BEGINNING OF PERIOD	$19,384	$15,272	$18,163	$13,761
Net Income	2,021	1,947	5,585	5,558
Cash Dividends Declared	1,172	1,050	3,515	3,150
BALANCE AT END OF PERIOD	$20,233	$16,169	$20,233	$16,169

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

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$645,047	$637,095
General	4,278	4,728
Construction Work in Progress	12,928	10,390
TOTAL	662,253	652,213
Accumulated Depreciation	374,740	358,174
TOTAL - NET	287,513	294,039
Other Property and Investments	119	119
CURRENT ASSETS		
Accounts Receivable - Affiliated Companies	20,481	18,454
Fuel	14,829	20,260
Materials and Supplies	5,179	4,913
Prepayments	24	-
TOTAL	40,513	43,627
Regulatory Assets	5,674	4,970
Deferred Charges	6,119	6,974
TOTAL ASSETS	$339,938	$349,729

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - Par Value $1 per share:		
Authorized and Outstanding - 1,000 Shares	$1,000	$1,000
Paid-in Capital	23,434	23,434
Retained Earnings	20,233	18,163
Total Common Shareholder's Equity	44,667	42,597
Long-term Debt	44,809	44,802
TOTAL	89,476	87,399
Other Noncurrent Liabilities	1,305	301
CURRENT LIABILITIES		
Advances from Affiliates	6,879	28,034
Accounts Payable:		
General	-	26
Affiliated Companies	14,176	15,907
Taxes Accrued	4,360	2,327
Rent Accrued - Rockport Plant Unit 2	23,427	4,963
Other	603	1,111
TOTAL	49,445	52,368
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	106,868	111,046
REGULATORY LIABILITIES		
Deferred Investment Tax Credit	50,440	52,943
Amounts Due to Customers for Income Taxes	15,191	16,670
TOTAL	65,631	69,613
Deferred Income Taxes	27,213	29,002
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$339,938	$349,729

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$5,585	$5,558
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation	16,981	16,918
Deferred Income Taxes	(3,268)	(3,328)
Deferred Investment Tax Credits	(2,503)	(2,504)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(4,178)	(4,178)
Changes in Certain Assets and Liabilities:		
Accounts Receivable	(2,027)	(11,370)
Fuel, Materials and Supplies	5,165	1,741
Accounts Payable	(1,757)	31,076
Taxes Accrued	2,033	4,225
Deferred Property Taxes	(795)	(881)
Rent Accrued - Rockport Plant Unit 2	18,464	18,464
Change in Other Assets	1,383	243
Change in Other Liabilities	(558)	(644)
Net Cash Flows From Operating Activities	34,525	55,320
INVESTING ACTIVITIES - Construction Expenditures	(9,855)	(6,956)
FINANCING ACTIVITIES		
Change in Advances from Affiliates	(21,155)	(46,197)
Dividends Paid	(3,515)	(3,150)
Net Cash Flows Used For Financing Activities	(24,670)	(49,347)
Net Decrease in Cash and Cash Equivalents	-	(983)
Cash and Cash Equivalents at Beginning of Period	-	983
Cash and Cash Equivalents at End of Period	$-	$-

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $2,200,000 and $1,983,000 and for income taxes was $5,939,000 and $2,442,000 in 2003 and 2002, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

Results of Operations

Net Income decreased $27 million for the third quarter, but increased $43 million year-to-date. The decreased income for the quarter is due to decreased margins on system sales, offset in part by the recognition of non-cash earnings related to legislatively mandated capacity auctions and regulatory assets established in Texas of $39 million net of tax. The increased income for the year-to-date is associated with the recognition of non-cash earnings related to the capacity auction true-up in Texas of $110 million net of tax, offset in part by decreased margins on system sales.

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

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

Third Quarter 2003 Compared to Third Quarter 2002

Operating Income

Operating Income decreased $34 million primarily due to:

o Decreased system sales, including those to REPs, of $75 million, due mainly to decreased KWH sales and a decrease in the overall average price per KWH.
o Decreased revenues from ERCOT for various services, including balancing energy, of $45 million.
o The 2002 ICR adjustments that accounted for approximately $60 million of the decrease (See "ICR Explanation: in Note 6 in the Annual Report, as updated by the Current Report on Form 8-K dated May 14, 2003, for discussion of the ICR adjustments).
o Decreased delivery revenues of $25 million partially due to a 7% decrease in cooling degree days.
o Decreased transmission revenues of $6 million.
o Increased fuel and purchased electricity on a combined basis of $10 million. Fuel increased almost entirely due to increased per unit fuel costs, which rose 54%, mostly due to natural gas prices. Purchased power decreased in large part due to the 2002 ICR adjustments of $51 million (see "ICR Explanation" in Note 6 in the Annual Report, as updated by the Current Report on Form 8-K dated May 14, 2003, for discussion of the ICR adjustments.) While purchased KWH increased 38%, the average cost per unit decreased 16%.
o Increased Other Operation expense of $3 million due mainly to accretion expense associated with the adoption of SFAS 143 (see Note 2).
o Increased maintenance expense of $1 million due mainly to unscheduled repairs at the STP nuclear plant.

The decrease in Operating Income was partially offset by:

o Reliability Must Run (RMR) revenues from ERCOT of $66 million which include both fuel recovery and a fixed cost component of $9 million (see "Texas Plants" in Note 13 in the Annual Report, as updated by the Current Report on Form 8-K dated May 14, 2003, for discussion of RMR facilities).
o Revenues associated with establishing regulatory assets in Texas of $61 million for the third quarter 2003 (see "Texas Restructuring" in Note 4).
o Increased revenues from risk management activities of $20 million.
o Decreased Depreciation and Amortization expense of $16 million due mainly to the reversal of prior years' excess earnings accruals under the Texas restructuring legislation due to a favorable Appeals Court ruling (See Note 4), decreases resulting from ARO (see Note 2), reduced depreciable plant due to the mothballing of certain generating units in 2002 and changes resulting from amortization of regulatory assets.
o Decreased Income Taxes of $26 million due mainly to decreases in pre-tax operating book income.

Other Impacts on Earnings

Nonoperating Income increased $15 million primarily due to increased gains from risk management activities partially offset by lower non-utility revenues associated with energy related construction projects for third parties.

Nonoperating Expense decreased $7 million primarily due to lower non-utility expenses associated with energy related construction projects for third parties.

Nonoperating Income Tax Expense (Credit) increased $8 million due to higher pre-tax nonoperating book income.

Interest Charges increased $7 million primarily due to increased average levels of debt outstanding during the quarter.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Operating Income

Operating Income increased $35 million primarily due to:

o Revenues associated with establishing regulatory assets in Texas of $169 million in 2003 (see "Texas Restructuring" in Note 4).
o Reliability Must Run (RMR) revenues from ERCOT of $188 million which include both fuel recovery and a fixed cost component of $26 million (see "Texas Plants" in Note 13 in the Annual Report, as updated by the Current Report on Form 8-K dated May 14, 2003, for discussion of RMR facilities).
o Increased revenues of $33 million resulting from risk management activities.
o Decreased Depreciation and Amortization expense of $23 million due mainly to decreases resulting from ARO (see Note 2), reduced depreciable plant due to the mothballing of certain generating units in 2002 and changes resulting from amortization of regulatory assets.
o Reduced Taxes Other Than Income Taxes of $9 million resulting from lower property taxes and state gross receipts taxes stemming from deregulation in Texas.

The increase in Operating Income was partially offset by:

o Decreased system sales, including those to REPs, of $34 million due mainly to both lower KWH sales and a decrease in the overall average price per KWH.
o Revenues from ERCOT for various services, including balancing energy, which declined $39 million.
o The 2002 ICR adjustments that accounted for approximately $60 million of the decrease (See "ICR Explanation" in Note 6 in the Annual Report, as updated by the Current Report on Form 8-K dated May 14, 2003, for discussion of the ICR adjustments).
o Decreased delivery revenues of $41 million driven by a 10% decrease in cooling degree days and a slight decrease in heating degree days.
o Increased provisions for rate refunds of $39 million due mainly to Texas fuel issues (see "TCC Fuel Reconciliation" in Note 3).
o Net increases in fuel and purchased electricity on a combined basis of $175 million to replace portions of the energy from the non-RMR mothballed plants and the unscheduled forced outage at the STP nuclear unit (See "Significant Factors" below). KWH purchased increased 108% while the total cost increased 90%. Although the KWH generated decreased, fuel costs increased due to 43% higher per unit costs attributable mostly to natural gas. This increase was partially offset by the effect of the 2002 ICR adjustments.
o Increased Maintenance expense of $14 million due mainly to the STP Unit 2 forced outage in the first quarter and the STP Unit 1 scheduled refueling outage and forced outage in the second and third quarters of 2003.
o Increased Income Taxes of $14 million due mainly to increases in pre-tax operating book income.

Other Impacts on Earnings

Nonoperating Income increased $19 million primarily due to increased gains from risk management activities partially offset by lower non-utility revenues associated with energy related construction projects for third parties.

Nonoperating Expense decreased $9 million primarily due to lower non-utility expenses associated with energy related construction projects for third parties.

Nonoperating Income Tax Expense (Credit) increased $9 million due to higher pre-tax nonoperating book income.

Interest Charges increased $11 million primarily due to the replacement of lower cost short-term floating rate debt with longer-term higher cost fixed rate debt.

Cumulative Effect of Accounting Change

This amount represents the one-time after-tax effect of the application of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

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

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

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of TCC's rating for unsecured debt from Baa1 to Baa2 and secured debt from A3 to Baa1. The completion of this review was a culmination of ratings action started during 2002. With the completion of the reviews, Moody's has placed AEP and its rated subsidiaries on stable outlook. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

Cash Flow

Cash flows for the nine months ended September 30, 2003 and 2002 were as follows:

	2003	2002
	(in thousands)	
Cash and cash equivalents at beginning of period	$85,420	$10,909
Cash flow from (used for):		
Operating activities	231,397	33,502
Investing activities	(94,818)	(97,952)
Financing activities	(179,247)	110,179
Net increase (decrease) in cash and cash equivalents	(42,668)	45,729
Cash and cash equivalents at end of period	$42,752	$56,638

Operating Activities

Cash flow from operating activities increased $198 million from the prior year primarily due to a $43 million increase in net income as explained above and accounts receivables changes related to reduced energy sales due primarily to REP related sales receivables, partially offset by the non-cash Texas wholesale capacity auction revenues recorded in 2003.

Investing Activities

Construction expenditures in 2003 versus 2002 decreased by $3 million. Construction expenditures of $95 million in the current year were focused on improved service reliability projects for transmission and distribution systems costing $68 million.

Financing Activities

We obtained the additional funds needed for investing and financing activities through new borrowings of $800 million in 2003 and $997 million in 2002. Current year debt proceeds replaced short and long-term debt. Prior year debt proceeds replaced long-term debt and retired common stock.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2003 were:

Issuances

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$150	3.00	2005
Senior Unsecured Notes	100	Variable	2005
Senior Unsecured Notes	275	5.50	2013
Senior Unsecured Notes	275	6.65	2033

Retirements

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
First Mortgage Bonds	$16	6.875	2003
First Mortgage Bonds	18	7.50	2023
Securitization Bonds	51	3.54	2005

Significant Factors

Possible Divestitures

In June 2003, we began actively seeking buyers for 4,497 megawatts of unregulated generation capacity in Texas. The value received from this disposition will be used to calculate our strande cost in Texas (see Note 4). We expect to receive final bids in the fourth quarter of 2003.

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. If we choose to dispose of these assets, we may realize non-recurring losses in the aggregate that could have a material impact on our results of operations, cash flows and financial condition.

Nuclear Plant Outage

In April 2003, engineers at STP, during inspections conducted regularly as part of scheduled 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.

Industry Restructuring

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), on January 1, 2002, customer choice began in the ERCOT area of Texas. Restructuring legislation generally provides for a transition from cost-based rate regulation of bundled electric service to customer choice and market pricing for the supply of electricity.

Restructuring legislation in Texas provides that the PUCT address several issues in the 2004 true-up proceeding. One of these issues is the wholesale capacity auction true-up. We have recorded $431 million of regulatory assets and related revenues through September 30, 2003 based upon our estimate.

In July 2003, the PUCT Staff published their proposed filing package for the 2004 true-up proceeding. Within the filing package are instructions and sample schedules that demonstrate the calculation of the wholesale capacity auction true-up. That calculation differs from our methodology. We filed comments on the proposed 2004 true-up filing package in September 2003 and took exception to the methodology employed by the PUCT Staff. A true-up filing package will probably be approved by the PUCT in the fourth quarter of 2003. If the PUCT Staff's methodology is approved, our wholesale capacity auction true-up regulatory asset could require adjustment.

In October 2003, a coalition of consumer groups (the Coalition of Ratepayers) including the Office of Public Utility Counsel, the State of Texas, Cities served by CPL and Texas Industrial Energy Consumers filed a petition with the PUCT requesting that the PUCT initiate a rulemaking to amend the PUCT's stranded cost true-up rule (True-up Rule). The Coalition of Ratepayers proposed to amend the True-up Rule to revise the calculation of the wholesale capacity auction true-up. If adopted, the Coalition of Ratepayers' proposal would substantially reduce or possibly eliminate the wholesale capacity auction true-up regulatory asset that we have accrued in 2002 and 2003. The PUCT requested that responses to the Coalition of Ratepayers' petition be filed by November 7, 2003. On November 5, 2003, the PUCT denied the Coalition of Ratepayers' petition.

See Notes 3 and 4 for further discussion.

In the event we are unable, after the 2004 true-up proceeding, to recover all or a portion of our generation-related regulatory assets, unrecovered fuel balances, stranded costs, 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.

Critical Accounting Policies

See "Registrants' Combined Management's Discussion and Analysis of Financial Condition, Accounting Policies and Other Matters - Critical Accounting Policies" in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Risk management policies and procedures are instituted and administered at the AEP consolidated level for all subsidiary registrants. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about the risk management activities' effect.

Roll-Forward of MTM Risk Management Contract Net Assets

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

Roll-Forward of MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2003
(in thousands)

Domestic Power

Beginning Balance December 31, 2002	$5,414
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(2,671)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	-
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of 98-10 Rescission	187
Changes in Fair Value of Risk Management Contracts (d)	16,097
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	-
Total MTM Risk Management Contract Net Assets	19,027
Net Non-Trading Related Derivative Contracts	464
Net Fair Value of Risk Management and Derivative Contracts September 30, 2003	$19,491

(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)"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.
(e)"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.

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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 September 30, 2003

	Remainder 2003	2004	2005	2006	2007	After 2007	Total
				(in thousands)			
Prices Provided by Other External Sources - OTC Broker Quotes (a)	$410	$4,572	$2,020	$1,771	$419	$-	$9,192
Prices Based on Models and Other Valuation Methods (b)	688	1,662	1,054	1,275	1,406	3,750	9,835
Total	$1,098	$6,234	$3,074	$3,046	$1,825	$3,750	$19,027

(a)"Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b)"Prices Based on Models and Other Valuation Methods" if there is 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.

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 Other Comprehensive Income (Loss) Activity Nine Months Ended September 30, 2003

	Domestic Power
(in thousands)	
Accumulated OCI, December 31, 2002	$(36)
Changes in Fair Value (a)	200
Reclassifications from OCI to Net Income (b)	137
Accumulated OCI Derivative Gain September 30, 2003	$301

(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 OCI 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 Accumulated OCI expected to be reclassified to earnings during the next twelve months is a $525 thousand gain.

Credit Risk

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

VaR Associated with Energy Trading Contracts

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

September 30, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$278	$788	$363	$78	$115	$353	$126	$26

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2003	2002	2003	2002
			(in thousands)	
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$443,578	$111,051	$1,264,757	$306,238
Sales to AEP Affiliates	41,551	435,209	131,176	879,323
TOTAL	485,129	546,260	1,395,933	1,185,561
OPERATING EXPENSES				
Fuel for Electric Generation	24,475	21,081	73,244	70,808
Fuel from Affiliates for Electric Generation	72,776	42,576	155,976	137,133
Purchased Electricity for Resale	116,562	151,012	305,338	160,996
Purchased Electricity from AEP Affiliates	273	(10,433)	19,045	10,058
Other Operation	74,192	71,023	213,884	208,984
Maintenance	16,657	15,239	54,567	40,980
Depreciation and Amortization	46,151	62,242	142,084	165,012
Taxes Other Than Income Taxes	24,747	24,774	67,509	76,170
Income Taxes	24,794	50,542	91,171	77,452
TOTAL	400,627	428,056	1,122,818	947,593
OPERATING INCOME	84,502	118,204	273,115	237,968
Nonoperating Income	25,006	10,234	43,069	24,237
Nonoperating Expenses	3,647	10,184	14,479	23,049
Nonoperating Income Tax Expense (Credit)	6,319	(1,522)	7,117	(2,037)
Interest Charges	33,321	26,393	100,343	89,830
Income Before Cumulative Effect of Accounting Change	66,221	93,383	194,245	151,363
Cumulative Effect of Accounting Change (Net of Tax)	-	-	122	-
NET INCOME	66,221	93,383	194,367	151,363
Gain on Reacquired Preferred Stock	-	4	-	4
Preferred Stock Dividend Requirements	60	60	181	181
EARNINGS APPLICABLE TO COMMON STOCK	$66,161	$ 93,327	$194,186	$151,186

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

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 2002	$168,888	$405,015	$826,197		$1,400,100
Redemption of Common Stock	(113,596)	(272,409)			(386,005)
Common Stock Dividends			(115,505)		(115,505)
Preferred Stock Dividends			(181)		(181)
Capital Stock Gains			4		4
TOTAL					898,413
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				$58	58
NET INCOME			151,363		151,363
TOTAL COMPREHENSIVE INCOME					151,421
SEPTEMBER 30, 2002	$55,292	$132,606	$861,878	$58	$1,049,834
JANUARY 1, 2003	$55,292	$132,606	$986,396	$(73,160)	$1,101,134
Common Stock Dividends			(90,601)		(90,601)
Preferred Stock Dividends			(181)		(181)
TOTAL					1,010,352
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				337	337
NET INCOME			194,367		194,367
TOTAL COMPREHENSIVE INCOME					194,704
SEPTEMBER 30, 2003	$55,292	$132,606	$1,089,981	$(72,823)	$1,205,056

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$3,001,939	$2,903,942
Transmission	776,256	698,964
Distribution	1,365,327	1,296,731
General	263,567	258,386
Construction Work in Progress	59,385	200,947
Nuclear Fuel	34,042	34,942
TOTAL	5,500,516	5,393,912
Accumulated Depreciation and Amortization	2,151,475	2,173,668
TOTAL - NET	3,349,041	3,220,244
Other Property and Investments	8,598	3,977
Securitized Transition Assets	703,293	734,591
Long-term Risk Management Assets	16,823	4,392
CURRENT ASSETS		
Cash and Cash Equivalents	42,752	85,420
Advances to Affiliates	26,327	-
Accounts Receivable:		
General	169,304	113,543
Affiliated Companies	110,360	121,324
Allowance for Uncollectible Accounts	(248)	(346)
Fuel Inventory	18,400	32,563
Materials and Supplies	48,696	51,593
Accrued Utility Revenues	34,757	27,150
Risk Management Assets	14,007	22,493
Prepayments and Other Current Assets	4,682	2,133
TOTAL	469,037	455,873
Regulatory Assets	659,427	458,552
Regulatory Assets Designated for or Subject to Securitization	320,713	336,444
Nuclear Decommissioning Trust Fund	114,930	98,474
Deferred Charges	66,962	43,891
TOTAL ASSETS	$5,708,824	$5,356,438

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - $25 Par Value:		
Authorized - 12,000,000 Shares		
Outstanding - 2,211,678 Shares	$55,292	$55,292
Paid-in Capital	132,606	132,606
Accumulated Other Comprehensive Income (Loss)	(72,823)	(73,160)
Retained Earnings	1,089,981	986,396
Total Common Shareholder's Equity	1,205,056	1,101,134
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,942
CPL - Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of TCC	-	136,250
Long-term Debt	2,081,274	1,209,434
TOTAL	3,292,270	2,452,760
Other Noncurrent Liabilities	326,943	74,572
CURRENT LIABILITIES		
Short-term Debt - Affiliates	-	650,000
Long-term Debt Due Within One Year	210,251	229,131
Advances from Affiliates	-	126,711
Accounts Payable:		
General	88,601	72,199
Affiliated Companies	91,655	36,242
Customer Deposits	1,411	666
Taxes Accrued	48,834	24,791
Interest Accrued	24,467	51,205
Risk Management Liabilities	6,030	19,811
Other	27,075	36,698
TOTAL	498,324	1,247,454
Deferred Income Taxes	1,281,787	1,261,252
Deferred Investment Tax Credits	113,781	117,686
Long-term Risk Management Liabilities	5,309	1,713
Regulatory Liabilities and Deferred Credits	190,410	201,001
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,708,824	$5,356,438

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$194,367	$151,363
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	142,084	165,012
Deferred Income Taxes	36,386	(14,620)
Deferred Investment Tax Credits	(3,905)	(3,905)
Cumulative Effect of Accounting Change	(122)	-
Mark-to-Market of Risk Management Contracts	(13,426)	(4,613)
Texas Wholesale Clawback	(169,000)	-
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(44,895)	(258,663)
Fuel, Materials and Supplies	17,060	(6,214)
Interest Accrued	(26,738)	17,375
Accrued Utility Revenues	(7,607)	-
Accounts Payable	71,815	(16,306)
Taxes Accrued	24,043	61,198
Deferred Property Tax	(10,050)	(9,560)
Change in Other Assets	14,359	(61,836)
Change in Other Liabilities	7,026	14,271
Net Cash Flows From Operating Activities	231,397	33,502
INVESTING ACTIVITIES		
Construction Expenditures	(95,425)	(97,952)
Other	607	-
Net Cash Flows Used For Investing Activities	(94,818)	(97,952)
FINANCING ACTIVITIES		
Change in Short-term Debt-Affiliates	(650,000)	200,000
Issuance of Long-term Debt	800,000	797,335
Retirement of Long-term Debt	(85,427)	(583,836)
Change in Advances to/from Affiliates, Net	(153,038)	198,371
Retirement of Common Stock	-	(386,005)
Dividends Paid on Common Stock	(90,601)	(115,505)
Dividends Paid on Cumulative Preferred Stock	(181)	(181)
Net Cash Flows From (Used For) Financing Activities	(179,247)	110,179
Net Increase (Decrease) in Cash and Cash Equivalents	(42,668)	45,729
Cash and Cash Equivalents at Beginning of Period	85,420	10,909
Cash and Cash Equivalents at End of Period	$42,752	$56,638

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $117,427,000 and $63,005,000 and for income taxes was $42,901,000 and $44,322,000 in 2003 and 2002, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

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

Results of Operations

Net Income increased $45 million year-to-date and $22 million for the third quarter primarily due to a $22 million write- down of inactivated power plants in 2002. Additionally, year-to-date net income was increased as a result of a Cumulative Effect of Accounting Changes of $3 million (see Note 2).

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

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

Third Quarter 2003 Compared to Third Quarter 2002

Operating Income

Operating Income increased by $18 million primarily due to:

o Reliability Must Run (RMR) revenues from ERCOT of $17 million, which include both fuel recovery and a fixed cost component of $3 million (see "Texas Plants" in Note 13 in the Annual Report, as updated by the Current Report on Form 8-K dated May 14, 2003, for discussion of RMR facilities).
o Increased revenues from risk management activities of $6 million.
o Decreased fuel and purchased electricity on a combined basis of $26 million due mainly to decreased KWH both generated and purchased because of reduced sales due partly to a 2% decline in cooling degree-days, and the effect of the 2002 ICR adjustments of $5 million (see "ICR Explanation" in Note 6 in the Annual Report as updated by the Current Report on Form 8-K dated May 14, 2003, for discussion of the ICR adjustments). KWH generation also decreased due to the inactivation of several plants in late 2002, offset in part by a 12% increase in per unit costs due to increases in natural gas prices.
o Reduced Other Operation expenses of $35 million resulting from the 2002 write-down of inactivated power plants.
o Reduced Depreciation and Amortization of $4 million mainly from adjustments to prior years' excess earnings accruals under the Texas restructuring legislation due to a favorable Appeals Court ruling (see Note 4) and reduced depreciable plant due to the inactivation of several power plants in late 2002.

The increase in Operating Income was partially offset by:

o Decreased system sales, including those to REPs, of $25 million due mainly to lower KWH
o Revenues from ERCOT for various services, including balancing energy, which declined $3 million.
o The 2002 ICR adjustments that accounted for approximately $25 million of the decrease in revenue (See "ICR Explanation" in Note 6 in the Annual Report, as updated by the Current Report on Form 8-K dated May 14, 2003, for discussion of the ICR adjustments.)
o Decreased delivery revenues of $7 million due partly to the decline in cooling degree-days.
o Reduced wholesale base revenues of $6 million due to the loss of several large wholesale customers whose contracts were not renewed.
o Increased provisions for rate refunds of $3 million in 2003.
o Increased Income Tax Expense (Credit) of $11 million due to increases in pre-tax operating book income.

Other Impacts on Earnings

Nonoperating Income increased $8 million primarily due to increases from risk management activities and non-utility revenues associated with energy-related construction projects for third parties.

Nonoperating Expense increased $2 million primarily due to higher non-utility expenses associated with energy-related construction projects for third parties.

Nonoperating Income Tax Expense (Credit) increased $2 million due to higher pre-tax nonoperating book income.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Operating Income

Operating Income increased by $34 million primarily due to:

o Reliability Must Run (RMR) revenues from ERCOT of $40 million which include both fuel recovery and a fixed cost component of $10 million (see "Texas Plants" in Note 13 in the Annual Report, as updated by the Current Report on Form 8-K dated May 14, 2003, for discussion of RMR facilities).
o Increased revenues from risk management activities of $9 million.
o Revenues from ERCOT for various services, including balancing energy, which increased $8 million.
o Reduced Other Operation expenses of $41 million due mainly to the 2002 write-down of inactivated power plants, along with slight decreases in customer, production and administrative expenses.
o Reduced Depreciation and Amortization of $8 million mainly from adjustments to prior years' excess earnings accruals under the Texas restructuring legislation due to a favorable Appeals Court ruling (See Note 4), and reduced depreciable plant due to the inactivation of several power plants in late 2002.
o Reduced Taxes Other Than Income Taxes of $3 million resulting from lower property taxes and state gross receipts taxes stemming from deregulation in Texas.

The increase in Operating Income was partially offset by:

o The 2002 ICR adjustments that accounted for approximately $25 million of the decrease in revenues (See "ICR Explanation" in Note 6 in the Annual Report, as updated by the Current Report on Form 8-K dated May 14, 2003, for discussion of the ICR adjustments.)
o Decreased delivery revenues of $7 million, due partly to decreased cooling and heating degree-days.
o Reduced wholesale base revenues of $13 million due to the loss of several large wholesale customers whose contracts expired and were not renewed.
o Increased provision for rate refunds of $12 million in 2003 (see "TNC Fuel Reconciliation" in Note 3).
o Increased fuel and purchased electricity on a combined basis of $4 million. KWH generation decreased 32% partly due to decreased cooling degree-days of 7% and heating degree-days of 1%, but the per unit cost of fuel increased 9% due to increased natural gas prices. KWH purchased declined 9%, but the average cost increased 9%, and the 2002 ICR adjustments served to decrease purchased power.
o Increased Income Tax Expense (Credit) of $22 million due to increases in pre-tax operating book income.

Other Impacts on Earnings

Nonoperating Income increased $34 million primarily due to increases from risk management activities and non-utility revenues associated with energy-related construction projects for third parties.

Nonoperating Expense increased $23 million primarily due to higher non-utility expenses associated with energy-related construction projects for third parties.

Nonoperating Income Tax Expense (Credit) increased $3 million due to higher pre-tax nonoperating book income.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to a one-time after-tax impact of adopting SFAS 143 (see Note 2).

Financial Condition

Credit Ratings

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

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

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. TNC had its secured debt downgraded from A2 to A3 and unsecured debt downgraded from A3 to Baa1. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and mortgage bonds ratings from BBB+ to BBB.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2003 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in millions)	(%)	
Senior Unsecured Notes	$225	5.50	2013

Retirements

None

Critical Accounting Policies

See "Registrants' Combined Management's Discussion and Analysis of Financial Condition, Accounting Policies and Other Matters - Critical Accounting Policies" in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Risk management policies and procedures are instituted and administered at the AEP consolidated level for all subsidiary registrants. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about the risk management activities' effects.

Roll-Forward of MTM Risk Management Contract Net Assets

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

Roll-Forward of MTM Risk Management Contract Net Assets

Nine Months Ended September 30, 2003
(in thousands)

Domestic Power

Beginning Balance December 31, 2002	$2,043
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(178)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	-
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of 98-10 Rescission	20
Changes in Fair Value of Risk Management Contracts (d)	4,518
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	445

Total MTM Risk Management Contract Net Assets	6,848
Net Non-Trading Related Derivative Contracts	178

Net Fair Value of Risk Management and Derivative Contracts September 30, 2003	$7,026
	=======

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" include 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)"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.
(e)"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.

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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 September 30, 2003

	Remainder 2003	2004	2005	2006	2007	After 2007	Total

	(in thousands)						
Prices Provided by Other External Sources - OTC Broker Quotes (a)	$148	$1,646	$727	$637	$151	$-	$3,309
Prices Based on Models and Other Valuation Methods (b)	247	598	379	459	506	1,350	3,539
Total	$395	$2,244	$1,106	$1,096	$657	$1,350	$6,848

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" if there is 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.

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 Other Comprehensive Income (Loss) Activity

Nine Months Ended September 30, 2003

	Domestic Power
	(in thousands)
Accumulated OCI, December 31, 2002	$(15)
Changes in Fair Value (a)	77
Reclassifications from OCI to Net Income (b)	53
Accumulated OCI Derivative Gain (Loss) September 30, 2003	$115

(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 OCI 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 Accumulated OCI expected to be reclassified to earnings during the next twelve months is a $201 thousand gain.

Credit Risk

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

VaR Associated with Energy Trading Contracts

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

September 30, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$106	$302	$139	$30	$48	$146	$52	$11

AEP TEXAS NORTH COMPANY
STATEMENTS OF OPERATIONS
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2003	2002	2003	2002
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$104,104	$ 62,041	$320,733	$155,375
Sales to AEP Affiliates	10,351	90,626	46,790	205,370
TOTAL	114,455	152,667	367,523	360,745
OPERATING EXPENSES				
Fuel for Electric Generation	9,457	8,276	29,196	26,289
Fuel from Affiliates for Electric Generation	14,390	15,498	31,392	55,307
Purchased Electricity for Resale	22,933	39,087	74,434	53,015
Purchased Electricity from AEP Affiliates	2,486	12,552	38,280	34,761
Other Operation	23,394	58,273	66,378	107,350
Maintenance	4,552	5,389	14,705	16,795
Depreciation and Amortization	7,132	11,513	26,387	34,154
Taxes Other Than Income Taxes	5,281	5,718	14,746	17,545
Income Tax Expense (Credit)	7,411	(3,331)	21,478	(855)
TOTAL	97,036	152,975	316,996	344,361
OPERATING INCOME (LOSS)	17,419	(308)	50,527	16,384
Nonoperating Income	23,581	15,446	54,877	20,938
Nonoperating Expenses	15,220	13,639	43,892	20,898
Nonoperating Income Tax Expense (Credit)	2,707	599	3,188	(33)
Interest Charges	5,726	5,093	16,290	15,983
Income (Loss) Before Cumulative Effect of Accounting Changes	17,347	(4,193)	42,034	474
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	3,071	-
NET INCOME (LOSS)	17,347	(4,193)	45,105	474
Preferred Stock Dividend Requirements	26	26	78	78
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$17,321	$(4,219)	$45,027	$396

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

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF COMMON SHAREHOLDER'S EQUITY AND
COMPREHENSIVE INCOME
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 2002	$137,214	$2,351	$105,970	$-	$245,535
Common Stock Dividends			(20,247)		(20,247)
Preferred Stock Dividends			(78)		(78)
TOTAL					225,210
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				17	17
NET INCOME			474		474
TOTAL COMPREHENSIVE INCOME					491
SEPTEMBER 30, 2002	$137,214	$2,351	$86,119	$17	$225,701
JANUARY 1, 2003	$137,214	$2,351	$71,942	$(30,763)	$180,744
Common Stock Dividends			(4,970)		(4,970)
Preferred Stock Dividends			(78)		(78)
Capital Stock Gain			3		3
TOTAL					175,699
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				130	130
Unrealized Loss on Minimum Pension Liability				(7)	(7)
NET INCOME			45,105		45,105
TOTAL COMPREHENSIVE INCOME					45,228
SEPTEMBER 30, 2003	$137,214	$2,351	$112,002	$(30,640)	$220,927

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$358,020	$353,087
Transmission	266,468	254,483
Distribution	454,255	445,486
General	113,303	111,679
Construction Work in Progress	31,171	37,012
TOTAL	1,223,217	1,201,747
Accumulated Depreciation and Amortization	531,854	521,792
TOTAL - NET	691,363	679,955
Other Property and Investments	1,167	1,213
Long-term Risk Management Assets	6,214	2,248
CURRENT ASSETS		
Cash and Cash Equivalents	2,742	1,219
Advances to Affiliates	15,075	-
Accounts Receivable:		
Customers	62,254	62,660
Affiliated Companies	29,395	43,632
Allowance for Uncollectible Accounts	(261)	(5,041)
Fuel Inventory	8,821	12,677
Materials and Supplies	10,772	9,574
Accrued Utility Revenues	5,888	6,829
Risk Management Assets	5,154	4,130
Prepayments and Other	1,243	1,070
TOTAL	141,083	136,750
Regulatory Assets	42,426	45,097
Deferred Charges	30,321	11,912
TOTAL ASSETS	$912,574	$877,175

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - $25 Par Value:		
Authorized - 7,800,000 Shares		
Outstanding - 5,488,560 Shares	$137,214	$137,214
Paid-in Capital	2,351	2,351
Accumulated Other Comprehensive Income (Loss)	(30,640)	(30,763)
Retained Earnings	112,002	71,942
Total Common Shareholder's Equity	220,927	180,744
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,367
Long-term Debt	332,686	132,500
TOTAL	555,970	315,611
Other Noncurrent Liabilities	41,911	28,861
CURRENT LIABILITIES		
Short-term Debt - Affiliates	-	125,000
Long-term Debt Due Within One Year	24,036	-
Advances from Affiliates	-	80,407
Accounts Payable:		
General	36,187	32,714
Affiliated Companies	32,196	76,217
Customer Deposits	209	117
Taxes Accrued	11,769	3,697
Interest Accrued	4,266	2,776
Risk Management Liabilities	2,309	3,801
Other	13,040	17,414
TOTAL	124,012	342,143
Deferred Income Taxes	119,802	117,521
Deferred Investment Tax Credits	20,370	21,510
Long-term Risk Management Liabilities	2,033	557
Regulatory Liabilities and Deferred Credits	48,476	50,972
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$912,574	$877,175

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CASH FLOWS
Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$45,105	$474
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	26,387	34,154
Write Down of Utility Plant Assets	-	34,215
Deferred Income Taxes	231	(14,139)
Deferred Investment Tax Credits	(1,140)	(953)
Cumulative Effect of Accounting Changes	(3,071)	-
Mark-to-Market of Risk Management Contracts	(4,786)	(2,863)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	9,863	(41,364)
Fuel, Materials and Supplies	2,658	(3,969)
Accrued Utility Revenues	941	-
Accounts Payable	(40,548)	(7,012)
Taxes Accrued	8,072	11,998
Fuel Recovery	-	9,161
Deferred Property Taxes	(3,323)	(3,588)
Change in Other Assets	(13,093)	(13,603)
Change in Other Liabilities	7,308	113
Net Cash Flows From Operating Activities	34,604	2,624
INVESTING ACTIVITIES		
Construction Expenditures	(33,136)	(33,338)
Other	595	-
Net Cash Flows Used For Investing Activities	(32,541)	(33,338)
FINANCING ACTIVITIES		
Change in Short-term Debt-Affiliates	(125,000)	-
Issuance of Long-term Debt	225,000	-
Retirement of Long-term Debt	-	(95,799)
Retirement of Preferred Stock	(10)	-
Change in Advances to/from Affiliates, Net	(95,482)	144,726
Dividends Paid on Common Stock	(4,970)	(20,247)
Dividends Paid on Cumulative Preferred Stock	(78)	(78)
Net Cash Flows From (Used For) Financing Activities	(540)	28,602
Net Increase (Decrease) in Cash and Cash Equivalents	1,523	(2,112)
Cash and Cash Equivalents at Beginning of Period	1,219	2,454
Cash and Cash Equivalents at End of Period	$2,742	$342

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $12,990,000 and $13,061,000 and for income taxes was $16,410,000 and $2,408,000 in 2003 and 2002, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

Results of Operations

Net Income for the first nine months of 2003 increased $61 million over the prior year period primarily due to the Cumulative Effect of Accounting Changes of $77 million recorded in the first quarter of 2003. This increase was partially offset by a $12 million decrease in net nonoperating income primarily due to reduced gains from risk management activities and increased Interest Charges of $5 million due to the effects of refinancing activities.

Net Income for the third quarter of 2003 decreased $8 million primarily due to an $18 million increase in capacity charges included in Purchased Electricity from AEP Affiliates partially offset by increased earnings from system sales and increased net nonoperating income. The cost of the AEP Power Pool's generating capacity is allocated among the Pool members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. We, as a member of the AEP Power Pool, share in the revenues and costs of marketing and activities conducted on our behalf by the AEP Power Pool. Our relative share of the AEP Power Pool revenues and expenses increased over the prior periods as a result of our reaching a new peak demand in January 2003, which increased our allocation factor.

Third Quarter 2003 Compared to Third Quarter 2002

Operating Income

Operating Income for the third quarter of 2003 decreased by $14 million from 2002 primarily due to the following:

o An increase in purchased power and fuel expense of $45 million reflecting the $18 million increase in capacity charges described above, the increase in our relative share of the AEP Power Pool expenses and the recently increased cost of coal.
o A decline in retail sales of $8 million resulting from decreased residential sales reflecting the mild weather conditions combined with lower industrial sales reflecting the continued weak economy. Cooling degree days for the quarter decreased 25% from the prior period.
o An $11 million decrease due to reduced gains from risk management activities.

The decrease in Operating Income for the third quarter of 2003 was partially offset by:

o An increase in system sales and transmission revenues totaling $29 million reflecting an increase in the volume of AEP Power Pool transactions, as well as our relative share based on the higher allocation factor.
o An increase of $9 million in Sales to AEP Affiliates.
o A decrease in income taxes of $7 million primarily due to the decrease in pre-tax operating book income.

Other Impacts on Earnings

Nonoperating Income increased $1 million for the third quarter primarily due to increased interest income on investments in the AEP Money Pool. The $2 million decrease in Nonoperating Income Tax Expense for third quarter was primarily due to a tax adjustment related to consolidated tax savings.

Interest Charges decreased $2 million for the third quarter primarily due to the early retirement of First Mortgage Bonds in the second quarter of 2003 partially offset by increased interest expense from a higher average balance of Senior Unsecured Notes (see Financing Activities section below).

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Operating Income

Operating Income for the first nine months of 2003 was relatively flat compared to the prior year.

The positive factors affecting Operating Income are as follows:

o System sales and transmission revenues increased $71 million over 2002, due to increased system sales volume, as well as our relative share based on the higher allocation factor.
o An increase in Sales to AEP Affiliates of $28 million.
o A decrease in Depreciation and Amortization expense of $13 million due primarily to the adoption of SFAS 143 (see Note 2). Additionally, we have reduced depreciation and amortization expense related to the amortization of generation related regulatory assets over the transition period due to the return to SFAS 71 for the West Virginia jurisdiction in the first quarter of 2003.

o An increase in gains from risk management activities of $12 million.

These increases in Operating Income for the first nine months of 2003 were offset by:

o An increase of $112 million in purchased power and fuel expense primarily due to a $41 million increase in capacity charges, the increase in our relative share of AEP Power Pool expenses and the recently increased cost of coal.
o An increase in Maintenance expense of $16 million, due primarily to increased maintenance at Amos and Sporn plants and maintenance of overhead lines required due to severe storm damage in the first quarter of 2003.

Other Impacts on Earnings

Nonoperating Income decreased $24 million for the nine months ended September 30, 2003, primarily due to a decrease in gains from risk management activities. Nonoperating Income Tax decreased $13 million for the nine months ended September 30, 2003 due to a decrease in pre-tax nonoperating book income and a tax adjustment related to consolidated tax savings.

Interest Charges increased $5 million for the nine months ended September 30, 2003, due to decreased AFUDC credits in 2003 compared to 2002 and call premiums relating to retirement of First Mortgage Bonds and Installment Purchase Contracts. (See Financing Activities).

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes of $77 million is due to the implementation of SFAS 143 and EITF 02-03 (see Note 2).

Financial Condition

Credit Ratings

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

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

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from Baa1 to Baa2 and a downgrade of secured ratings from A3 to Baa1. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and its subsidiaries senior unsecured ratings from BBB+ to BBB along with the first mortgage bonds of AEP subsidiaries.

Cash Flow

Cash flows for nine months ended September 30, 2003 and 2002 were as follows:

	2003	2002
	(in thousands)	
Cash and cash equivalents at beginning of period	$4,285	$13,663
Cash flow from (used for):		
Operating activities	404,828	229,160
Investing activities	(187,969)	(171,831)
Financing activities	(215,877)	(61,564)
Net increase (decrease) in cash and cash equivalents	982	(4,235)
Cash and cash equivalents at end of period	$5,267	$9,428

Operating Activities

Cash flow from operating activities increased $176 million primarily due to decreases in various accounts receivable balances in the nine months ended September 30, 2003.

Investing Activities

Construction expenditures in 2003 versus 2002 increased $15 million. The current year expenditures of $190 million were focused primarily on projects to improve service reliability for transmission and distribution, as well as environmental upgrades.

Financing Activities

In 2003, we issued two series of Senior Unsecured Notes, each in the amount of $200 million which were used to call First Mortgage Bonds and fund maturities. Additionally, we incurred obligations of $100 million in Installment Purchase Contracts which were used to redeem higher costing Installment Purchase Contracts.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2003 were:

Issuances

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$200	3.60	2008
Senior Unsecured Notes	200	5.95	2033
Installment Purchase Contracts	100	5.50	2022

Retirements

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
First Mortgage Bonds	$70	8.50	2022
First Mortgage Bonds	30	7.80	

2023			
	First Mortgage Bonds	20	7.15
2023			
	Installment Purchase Contracts	10	7.875
2013			
	Installment Purchase Contracts	40	6.85
2022			
	Installment Purchase Contracts	50	6.60
2022			
	Senior Unsecured Notes	100	7.20
2038			
	Senior Unsecured Notes	100	7.30
2038			
	Senior Unsecured Notes	125	Variable
2003			

Significant Factors

Federal EPA Complaint and Notice of Violation

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), we are involved in litigation regarding generating plant emissions under the Clean Air Act. The Federal EPA and a number of states alleged APCo and certain affiliated companies and eleven unaffiliated utilities made modifications to generating units at coal-fired generating plants in violation of the Clean Air Act. The Federal EPA filed complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20 year period.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the Clear Air Act proceedings and is 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. In the event 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. See Note 5 for further discussion.

NOx Reductions

The Federal EPA issued a NOx Rule and adopted a revised rule (the Section 126 Rule) under the Clean Air Act requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. The compliance date for the rules is May 31, 2004.

We are installing selective catalytic reduction (SCR) technology and other combustion control technology to reduce NOx emissions on certain units to comply with these rules.

Our estimates indicate that compliance with the rules could result in required capital expenditures of approximately $464 million. The actual cost to comply could be significantly different than the estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital or operating costs for additional pollution control equipment are recovered from customers, these costs would adversely affect future results of operations, cash flows and possibly financial condition (see Note 5).

RTO Formation

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), 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 AEP's transmission system to RTOs. Furthermore, legislation in certain states in which AEP subsidiaries operate 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 AEP's 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, we filed with the Virginia SCC for approval of our plan to transfer functional control of our transmission assets to PJM. In February 2003, Virginia enacted legislation that prohibited the transfer of transmission assets in its jurisdiction to an RTO until, at the earliest, July 2004 and only with the approval of Virginia SCC.

We are 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 (see Note 3).

Critical Accounting Policies

See "Registrants' Combined Management's Discussion and Analysis of Financial Condition, Accounting Policies and Other Matters - Critical Accounting Policies" in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Risk management policies and procedures are instituted and administered at the AEP consolidated level for all subsidiary registrants. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about the risk management activities' effect on this specific registrant.

Roll-Forward of MTM Risk Management Contract Net Assets

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

Roll-Forward of MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$96,852
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(34,984)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	265
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of 98-10 Rescission	(4,664)
Changes in Fair Value of Risk Management Contracts (d)	2,022
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(1,030)
Total MTM Risk Management Contract Net Assets	58,461

Net Non-Trading Related Derivative Contracts	1,561

Net Fair Value of Risk Management and Derivative Contracts September 30, 2003	$60,022
	========

(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)"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.
(e)"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.

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:
o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 September 30, 2003

	Remainder 2003	2004	2005	2006	2007	After 2007	Total
			(in thousands)				
Prices Actively Quoted - Exchange Traded Contracts	$(291)	$53	$(266)	$-	$-	$-	$(504)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	1,259	14,602	6,200	5,436	1,287	-	28,784
Prices Based on Models and Other Valuation Methods (b)	2,109	5,098	3,236	3,913	4,315	11,510	30,181
Total	$3,077	$19,753	$9,170	$9,349	$5,602	$11,510	$58,461

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" if there is 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.

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).

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.

Total Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2003

	Domestic Power	Foreign Currency	Interest Rate	Consolidated
		(in thousands)		
Accumulated OCI, December 31, 2002	$(394)	$(190)	$(1,336)	$(1,920)
Changes in Fair Value (a)	785	-	(719)	66
Reclassifications from OCI to Net Income (b)	475	5	226	706
Accumulated OCI Derivative Gain (Loss) September 30, 2003	$866	$(185)	$(1,829)	$(1,148)

(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 OCI 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 Accumulated OCI expected to be reclassified to earnings during the next twelve months is a $1,167 thousand gain.

Credit Risk

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

VaR Associated with Energy Trading Contracts

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

September 30, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$800	$2,271	$1,046	$226	$1,289	$3,948	$1,412	$286

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2003	2002	2003	2002
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$428,667	$418,159	$1,297,255	$1,220,039
Sales to AEP Affiliates	54,944	46,250	167,335	138,990
TOTAL	483,611	464,409	1,464,590	1,359,029
OPERATING EXPENSES				
Fuel for Electric Generation	113,274	107,514	345,819	322,164
Purchased Electricity for Resale	18,365	13,174	50,745	41,635
Purchased Electricity from AEP Affiliates	92,857	58,395	257,382	177,892
Other Operation	64,065	67,255	192,806	197,631
Maintenance	31,855	32,053	101,420	85,542
Depreciation and Amortization	46,501	47,692	128,574	141,373
Taxes Other Than Income Taxes	23,232	23,881	70,583	73,926
Income Taxes	26,328	33,080	88,387	90,723
TOTAL	416,477	383,044	1,235,716	1,130,886
OPERATING INCOME	67,134	81,365	228,874	228,143
Nonoperating Income	7,809	6,627	2,878	26,644
Nonoperating Expenses	4,217	4,865	10,219	9,170
Nonoperating Income Tax Expense (Credit)	(1,307)	538	(7,491)	5,622
Interest Charges	26,318	28,642	89,520	84,099
Income Before Cumulative Effect of Accounting Changes	45,715	53,947	139,504	155,896
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	77,257	-
NET INCOME	45,715	53,947	216,761	155,896
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	703	502	2,671	1,508
EARNINGS APPLICABLE TO COMMON STOCK	$45,012	$53,445	$214,090	$154,388

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

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 2002	$260,458	$715,786	$150,797	$(340)	$1,126,701
Common Stock Dividends			(92,952)		(92,952)
Preferred Stock Dividends			(1,082)		(1,082)
Capital Stock Expense		426	(426)		-
TOTAL					1,032,667
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(1,387)	(1,387)
NET INCOME			155,896		155,896
TOTAL COMPREHENSIVE INCOME					154,509
SEPTEMBER 30, 2002	$260,458	$716,212	$212,233	$ (1,727)	$1,187,176
JANUARY 1, 2003	$260,458	$717,242	$260,439	$(72,082)	$1,166,057
Common Stock Dividends			(96,200)		(96,200)
Preferred Stock Dividends			(801)		(801)
Capital Stock Expense		1,870	(1,870)		-
SFAS 71 Reapplication		162			162
TOTAL					1,069,218
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				772	772
NET INCOME			216,761		216,761
TOTAL COMPREHENSIVE INCOME					217,533
SEPTEMBER 30, 2003	$260,458	$719,274	$378,329	$(71,310)	$1,286,751

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,286,567	$2,245,945
Transmission	1,236,108	1,218,108
Distribution	1,991,491	1,951,804
General	280,309	272,901
Construction Work in Progress	254,387	206,545
TOTAL	6,048,862	5,895,303
Accumulated Depreciation and Amortization	2,381,700	2,424,607
TOTAL - NET	3,667,162	3,470,696
Other Property and Investments	49,356	54,653
Long-term Risk Management Assets	83,520	115,748
CURRENT ASSETS		
Cash and Cash Equivalents	5,267	4,285
Advances to Affiliates	34,434	-
Accounts Receivable:		
Customers	110,481	132,266
Affiliated Companies	90,591	122,665
Miscellaneous	26,072	28,629
Allowance for Uncollectible Accounts	(2,570)	(13,439)
Fuel Inventory	33,235	53,646
Materials and Supplies	74,095	59,886
Accrued Utility Revenues	7,822	30,948
Risk Management Assets	57,957	94,238
Prepayments and Other	16,833	13,396
TOTAL	454,217	526,520
Regulatory Assets	402,559	395,553
Deferred Charges	45,562	64,677
TOTAL ASSETS	$4,702,376	$4,627,847

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - No Par Value:		
Authorized - 30,000,000 Shares		
Outstanding - 13,499,500 Shares	$260,458	$260,458
Paid-in Capital	719,274	717,242
Accumulated Other Comprehensive Income (Loss)	(71,310)	(72,082)
Retained Earnings	378,329	260,439
Total Common Shareholder's Equity	1,286,751	1,166,057
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,790	17,790
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	10,860	10,860
Long-term Debt	1,802,332	1,738,854
TOTAL	3,117,733	2,933,561
Other Noncurrent Liabilities	190,379	173,438
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	51,008	155,007
Advances from Affiliates	-	39,205
Accounts Payable:		
General	120,319	141,546
Affiliated Companies	61,670	98,374
Taxes Accrued	47,182	29,181
Customer Deposits	31,776	26,186
Interest Accrued	42,791	22,437
Risk Management Liabilities	36,278	69,001
Other	70,473	79,832
TOTAL	461,497	660,769
Deferred Income Taxes	755,125	701,801
Deferred Investment Tax Credits	31,752	33,691
Long-term Risk Management Liabilities	45,177	44,517
Regulatory Liabilities and Deferred Credits	100,713	80,070
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$4,702,376	$4,627,847

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$216,761	$155,896
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	(77,257)	-
Depreciation and Amortization	128,574	141,457
Deferred Income Taxes	3,394	10,257
Deferred Investment Tax Credits	(1,940)	(3,295)
Deferred Power Supply Costs, Net	71,815	-
Mark to Market of Risk Management Contracts	33,727	(27,710)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	45,547	(83,288)
Fuel, Materials and Supplies	6,202	5,176
Accrued Utility Revenues	23,126	7,547
Accounts Payable	(57,931)	(26,948)
Taxes Accrued	18,001	39,660
Interest Accrued	20,354	13,487
Incentive Plan Accrued	(8,789)	-
Rate Stabilization Deferral	(75,601)	-
Change in Other Assets	19,748	(7,697)
Change in Other Liabilities	39,097	4,618
Net Cash Flows From Operating Activities	404,828	229,160
INVESTING ACTIVITIES		
Construction Expenditures	(190,047)	(175,314)
Proceeds from Sale of Property and Other	2,078	3,483
Net Cash Flows Used For Investing Activities	(187,969)	(171,831)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	500,000	444,110
Change in Advances to/from Affiliates, Net	(73,639)	(126,640)
Retirement of Long-term Debt	(545,237)	(285,000)
Dividends Paid on Common Stock	(96,200)	(92,952)
Dividends Paid on Cumulative Preferred Stock	(801)	(1,082)
Net Cash Flows Used For Financing Activities	(215,877)	(61,564)
Net Increase (Decrease) in Cash and Cash Equivalents	982	(4,235)
Cash and Cash Equivalents at Beginning of Period	4,285	13,663
Cash and Cash Equivalents at End of Period	$5,267	$9,428

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $63,481,000 and $68,305,000 and for income taxes was $47,419,000 and $38,425,000 in 2003 and 2002, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

Results of Operations

The decrease in Net Income of $13 million in the third quarter of 2003 compared to the third quarter of 2002 was primarily due to a $27 million decrease in retail electricity sales and a $12 million decrease in revenues from risk management activities, which were partially offset by a $4 million increase in sales to AEP affiliated companies and a $23 million decrease in income taxes. As a member of the AEP Power Pool, we share in the revenues and costs of marketing and activities conducted by the AEP Power Pool on our behalf.

The decrease in Net Income of $4 million for the nine months ended September 30, 2003 compared to the same period in 2002 was primarily due to a $41 million increase in fuel and purchased power expenses and a $28 million decrease in revenues from risk management activities, partially offset by a $31 million decrease in income taxes and a $27 million net-of-tax Cumulative Effect of Accounting Changes.

Third Quarter 2003 Compared to Third Quarter 2002

Operating Income

Operating Income decreased by $18 million primarily due to:

o Milder weather and a sluggish economy that resulted in decreased retail revenues of $27 million. Cooling degree days for the quarter decreased 36% from the prior period.
o A $10 million decrease in risk management income due to unfavorable market conditions and reduced activity.
o Increased purchased electricity of $10 million due to increased usage of the AEP Power Pool to meet load requirements.
o An increase of $5 million in Maintenance expense due to boiler overhaul work from scheduled and forced outages and maintenance of overhead lines resulting from severe storm damage.

The decrease in Operating Income was partially offset by:

o An increase of $4 million in Sales to AEP Affiliates.
o A decrease in Other Operation expense of $5 million primarily due to decreases in factored receivable expenses, AEP transmission equalization expenses and miscellaneous distribution expenses.
o A decrease in Income Taxes of $18 million primarily due to a decrease in pre-tax operating book income.

Other Impacts on Earnings

Nonoperating Income Tax Expense decreased $5 million primarily due to a tax adjustment related to consolidated tax savings.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Operating Income

Operating Income decreased $23 million primarily due to:

o Milder spring and summer weather and a sluggish economy resulting in decreased retail revenues of $37 million. Cooling degree days have decreased 41% year-to-date from the prior period.
o An increase in the AEP system pool capacity charge of $5 million.
o A $13 million increase in Maintenance expense due primarily to boiler overhaul work from scheduled and forced outages and maintenance of overhead lines resulting from severe storm damage.
o A $10 million increase in fuel expense due to higher coal costs.
o An increase of $28 million in Purchased Electricity from AEP Affiliates due to increased load requirements.

The decrease in Operating Income was partially offset by:

o An increase of $20 million of Sales to AEP Affiliates and an increase of $25 million of sales to non-affiliates.
o A decrease in Other Operation expense of $12 million primarily due to decreases in factored receivable expenses, AEP transmission equalization expenses and miscellaneous distribution expenses.
o Income Taxes decreased by $17 million primarily due to a decrease in pre-tax operating book income.

Other Impacts on Earnings

Nonoperating Income decreased $22 million primarily due to a reduction of risk management activities as a result of AEP's decision to exit wholesale markets where it does not own assets.

Nonoperating Income Tax Credit increased due to a decrease in pre-tax nonoperating book income and a tax adjustment related to consolidated tax savings.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

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

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

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and its subsidiaries senior unsecured ratings from BBB+ to BBB along with the first mortgage bonds of AEP subsidiaries.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2003 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in millions)	(%)	
Senior Unsecured Notes	$250	5.50	2013
Senior Unsecured Notes	250	6.60	2033

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date

	(in millions)	(%)	
First Mortgage Bonds	$2	8.70	2022
First Mortgage Bonds	15	8.55	2022
First Mortgage Bonds	14	8.40	2022
First Mortgage Bonds	13	8.40	2022
First Mortgage Bonds	13	6.80	2003
First Mortgage Bonds	26	6.55	2004
First Mortgage Bonds	26	6.75	2004
First Mortgage Bonds	40	7.90	2023
First Mortgage Bonds	33	7.75	2023
First Mortgage Bonds	25	6.60	2003

Intercompany Retirement of Debt Due to AEP

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Notes Payable	$160	6.501	2006

Significant Factors

Federal EPA Complaint and Notice of Violation

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), we are involved in litigation regarding generating plant emissions under the Clean Air Act. The Federal EPA and a number of states alleged CSPCo, certain affiliated companies and eleven unaffiliated utilities made modifications to generating units at coal-fired generating plants in violation of the Clean Air Act. The Federal EPA filed complaints against us in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20 year period.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the Clear Air Act proceedings and is 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. In the event 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. See Note 5 for further discussion.

NOx Reductions

The Federal EPA issued a NOx Rule and adopted a revised rule (the Section 126 Rule) under the Clean Air Act requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. The compliance date for the rules is May 31, 2004.

We are installing combustion control technology to reduce NOx emissions on certain units to comply with these rules.

Our estimates indicate that compliance with the rules could result in required capital expenditures of approximately $87 million. The actual cost to comply could be significantly different than the estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital or operating costs for additional pollution control equipment are recovered from customers, these costs would adversely affect future results of operations, cash flows and possibly financial condition. See Note 5 for further discussion.

Critical Accounting Policies

See "Registrants' Combined Management's Discussion and Analysis of Financial Condition, Accounting Policies and Other Matters - Critical Accounting Policies" in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Risk management policies and procedures are instituted and administered at the AEP consolidated level for all subsidiary registrants. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about the risk management activities' effect on this specific registrant.

Roll-Forward of MTM Risk Management Contract Net Assets

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

Roll-Forward of MTM Risk Management Contract Net Assets

Nine Months Ended September 30, 2003 (in thousands)	
Domestic Power	
Beginning Balance December 31, 2002	$65,117
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(23,524)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	149
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of 98-10 Rescission	(3,135)
Changes in Fair Value of Risk Management Contracts (d)	(5,681)
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	-
Total MTM Risk Management Contract Net Assets	32,926
Net Non-Trading Related Derivative Contracts	901
Net Fair Value of Risk Management and Derivative Contracts September 30, 2003	$33,827

(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)"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.
(e)"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.

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:
o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 September 30, 2003

	Remainder 2003	2004	2005	2006	2007	After 2007	Total
			(in thousands)				
Prices Actively Quoted - Exchange Traded Contracts	$(164)	$30	$(150)	$-	$-	$-	$(284)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	709	8,224	3,492	3,061	725	-	16,211
Prices Based on Models and Other Valuation Methods (b)	1,189	2,871	1,823	2,204	2,430	6,482	16,999
Total	$1,734	$11,125	$5,165	$5,265	$3,155	$6,482	$32,926

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" if there is 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.

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 Other Comprehensive Income (Loss) Activity Nine Months Ended September 30, 2003

	Domestic Power
	(in thousands)

Accumulated OCI, December 31, 2002	$(267)
Changes in Fair Value (a)	484
Reclassifications from OCI to Net Income (b)	271
Accumulated OCI Derivative Gain (Loss) September 30, 2003	$ 488

(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 OCI 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 Accumulated OCI expected to be reclassified to earnings during the next twelve months is a $851 thousand gain.

Credit Risk

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

VaR Associated with Energy Trading Contracts

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

September 30, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$450	$1,279	$589	$127	$867	$2,654	$949	$192

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2003	2002	2003	2002
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$375,936	$404,568	$1,027,732	$1,038,254
Sales to AEP Affiliates	21,719	17,324	62,199	42,277
TOTAL	397,655	421,892	1,089,931	1,080,531
OPERATING EXPENSES				
Fuel for Electric Generation	50,355	47,228	146,422	135,942
Purchased Electricity for Resale	5,688	3,569	13,898	11,124
Purchased Electricity from AEP Affiliates	93,486	85,228	263,225	235,432
Other Operation	57,348	62,393	166,027	178,042
Maintenance	19,630	14,878	56,801	44,068
Depreciation and Amortization	34,442	33,450	101,478	98,588
Taxes Other Than Income Taxes	34,970	37,570	101,532	97,176
Income Taxes	30,543	48,543	70,787	87,538
TOTAL	326,462	332,859	920,170	887,910
OPERATING INCOME	71,193	89,033	169,761	192,621
Nonoperating Income (Loss)	4,169	5,360	(2,587)	19,751
Nonoperating Expenses	550	1,014	2,944	1,432
Nonoperating Income Tax Expense (Credit)	(84)	4,590	(5,231)	9,387
Interest Charges	12,071	12,672	38,946	39,857
Income Before Cumulative Effect of Accounting Changes	62,825	76,117	130,515	161,696
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	27,283	-
NET INCOME	62,825	76,117	157,798	161,696
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	254	254	762	1,112
EARNINGS APPLICABLE TO COMMON STOCK	$62,571	$75,863	$157,036	$160,584

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

See Notes to Respective Financial Statements beginning on Page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 2002	$41,026	$574,369	$176,103		$791,498
Common Stock Dividends Declared			(65,300)		(65,300)
Preferred Stock Dividends Declared			(350)		(350)
Capital Stock Expense		762	(762)		-
					725,848
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				$326	326
NET INCOME			161,696		161,696
TOTAL COMPREHENSIVE INCOME					162,022
SEPTEMBER 30, 2002	$41,026	$575,131	$271,387	$326	$887,870
JANUARY 1, 2003	$41,026	$575,384	$290,611	$(59,357)	$847,664
Common Stock Dividends Declared			(124,932)		(124,932)
Capital Stock Expense		762	(762)		-
					722,732
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				755	755
NET INCOME			157,798		157,798
TOTAL COMPREHENSIVE INCOME					158,553
SEPTEMBER 30, 2003	$41,026	$576,146	$322,715	$(58,602)	$881,285

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,601,987	$1,582,627
Transmission	422,717	413,286
Distribution	1,247,229	1,208,255
General	158,810	165,025
Construction Work in Progress	107,581	98,433
TOTAL	3,538,324	3,467,626
Accumulated Depreciation and Amortization	1,468,746	1,465,174
TOTAL - NET	2,069,578	2,002,452
Other Property and Investments	31,840	35,759
Long-term Risk Management Assets	47,039	77,810
CURRENT ASSETS		
Cash and Cash Equivalents	4,909	1,479
Advances to Affiliates, Net	-	31,257
Accounts Receivable:		
Customers	33,157	49,566
Affiliated Companies	40,385	54,518
Miscellaneous	21,090	22,005
Allowance for Uncollectible Accounts	(575)	(634)
Fuel	15,231	24,844
Materials and Supplies	46,626	40,339
Accrued Utility Revenues	16,963	12,671
Risk Management Assets	32,664	63,348
Prepayments and Other	10,458	7,308
TOTAL	220,908	306,701
Regulatory Assets	247,403	257,682
Deferred Charges	35,047	72,836
TOTAL ASSETS	$2,651,815	$2,753,240

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - No Par Value:		
Authorized - 24,000,000 Shares		
Outstanding - 16,410,426 Shares	$41,026	$41,026
Paid-in Capital	576,146	575,384
Accumulated Other Comprehensive Income (Loss)	(58,602)	(59,357)
Retained Earnings	322,715	290,611
Total Common Shareholder's Equity	881,285	847,664
Long-term Debt:		
Nonaffiliated	747,806	418,626
Affiliated	-	160,000
Total Long-term Debt	747,806	578,626
TOTAL	1,629,091	1,426,290
Other Noncurrent Liabilities	88,683	95,460
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	5,000	43,000
Short-term Debt - Affiliates	-	290,000
Advances from Affiliates, Net	151,575	-
Accounts Payable - General	53,325	89,736
Accounts Payable - Affiliated Companies	43,603	81,599
Taxes Accrued	78,304	112,172
Interest Accrued	7,744	9,798
Risk Management Liabilities	20,432	46,375
Other	51,021	36,790
TOTAL	411,004	709,470
Deferred Income Taxes	451,638	437,771
Deferred Investment Tax Credits	31,619	33,907
Long-term Risk Management Liabilities	25,444	29,926
Deferred Credits and Regulatory Liabilities	14,336	20,416
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,651,815	$2,753,240

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$157,798	$161,696
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	(27,283)	-
Depreciation and Amortization	101,478	98,666
Deferred Income Taxes	(3,942)	12,450
Deferred Investment Tax Credits	(2,288)	(2,335)
Mark-to-Market of Risk Management Contracts	29,056	(21,033)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	31,398	(33,529)
Fuel, Materials and Supplies	3,326	(2,391)
Accrued Utility Revenues	(4,292)	(14,925)
Prepayments and Other Current Assets	(3,150)	(6,991)
Accounts Payable	(74,407)	(10,506)
Taxes Accrued	(33,868)	5,597
Interest Accrued	(2,054)	1,485
Deferred Property Tax	46,478	31,968
Change in Other Assets	(12,882)	(3,155)
Change in Other Liabilities	(4,496)	10,733
Net Cash Flows From Operating Activities	200,872	227,730
INVESTING ACTIVITIES		
Construction Expenditures	(98,032)	(88,101)
Proceeds from Sale of Property	190	730
Net Cash Flows Used For Investing Activities	(97,842)	(87,371)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	500,000	160,000
Change in Advances to/from Affiliates, Net	182,832	(206,501)
Retirement of Long-term Debt - Nonaffiliated	(207,500)	(112,843)
Retirement of Long-term Debt - Affiliated	(160,000)	(200,000)
Retirement of Cumulative Preferred Stock	-	(10,000)
Change in Short-term Debt - Affiliates	(290,000)	290,000
Dividends Paid on Common Stock	(124,932)	(65,300)
Dividends Paid on Cumulative Preferred Stock	-	(525)
Net Cash Flows Used For Financing Activities	(99,600)	(145,169)
Net Increase (Decrease) in Cash and Cash Equivalents	3,430	(4,810)
Cash and Cash Equivalents at Beginning of Period	1,479	12,358
Cash and Cash Equivalents at End of Period	$4,909	$7,548

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $39,804,000 and $37,204,000 and for income taxes was $48,955,000 and $32,254,000 in 2003 and 2002, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

Results of Operations

In the third quarter of 2003, Net Income increased $2 million reflecting reduced financing costs. Net Income increased $10 million including an unfavorable $3 million Cumulative Effect of Accounting Change in the first nine months of 2003 (see Note 2). For the nine months ended September 30, 2003, Net Income Before Cumulative Effect of Accounting Change increased $13 million due to an improvement in earnings primarily during the first quarter of 2003 from retail and AEP Power Pool sales resulting from the interactions of plant availability, colder winter weather and higher margins partially offset by the weak economy. As a member of the AEP Power Pool, we share in the revenues and costs of marketing and activities conducted by the AEP Power Pool on our behalf.

Third Quarter 2003 Compared to Third Quarter 2002

Operating Income

Operating Income decreased less than $1 million primarily due to:

o Decreased retail revenues of $22 million due primarily to milder weather during the third quarter of 2003 and economic pressures on industrial customers. Cooling degree days declined approximately 33% this year compared with last year. Industrial revenues dropped 5% from last year.
o Increased Fuel for Electric Generation expense of $2 million reflecting an increase in the average cost of fuel.
o Increased Purchased Electricity from AEP Affiliates of $9 million due to purchasing more power from the AEP Power Pool to support wholesale sales to unaffiliated entities.

The decrease in Operating Income during the third quarter was offset by:

o Increased sales to AEP Affiliates of $6 million due to increased capacity revenue.
o Increased wholesale sales including system and power optimization sales, transmission revenues and risk management activities of $25 million reflecting availability of AEP's generation and market conditions.
o A $3 million decrease in Maintenance expense due to an insurance recovery for costs incurred related to an influx of fish at Cook Plant. See Significant Factors section below.

Other Impacts on Earnings

Interest Charges decreased $4 million in the third quarter 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.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Operating Income

Operating Income increased $27 million primarily due to the following:

o Wholesale revenues increased $61 million reflecting market conditions.
o Sales to AEP Affiliates increased by $43 million due to more power being available for sale in 2003 and increased capacity revenues. In 2002, both units of Cook plant was shut down for refueling and both Rockport units were down for planned boiler maintenance.
o A decline in Other Operation expense of $22 million due to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and having two refueling outages in 2002 versus one refueling outage in 2003.
o An $8 million decrease in Taxes Other Than Income Taxes reflects a favorable tax law change in Indiana effective March 2002 and a lower estimate for Cook Plant's assessed value, which reduced real and personal property tax estimates on which 2003 accruals are based.

The year-to-date increase in Operating Income was partially offset by:

o A $23 million decline in retail revenues reflecting milder summer weather and lower industrial sales reflecting economic pressure.
o Increased Fuel for Electric Generation expense of $33 million reflecting an increase in the average cost of fuel and increased generation.
o Increased Purchased Electricity from AEP Affiliates of $31 million due to higher power purchases from AEGCo and the AEP Power Pool in 2003 compared to 2002 when outages at both units of the Rockport Plant decreased available power and purchases of replacement power during 2003 Cook forced outages.

o Increased Income Taxes of $11 million reflecting an increase in pre-tax income.

Other Impacts on Earnings

Nonoperating Income decreased $20 million year-to-date primarily due to lower margins for power sold outside of AEP's traditional marketing area reflecting AEP's plan to exit those risk management activities.

Interest Charges decreased $6 million year-to-date 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).

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 nine months ended September 30, 2003 and 2002 were as follows:

	2003	2002
	(in thousands)	
Cash and cash equivalents at beginning of period	$3,237	$16,804
Cash flow from (used for):		
Operating activities	191,018	161,460
Investing activities	(106,546)	(91,360)
Financing activities	(83,634)	(77,902)
Net increase (decrease) in cash and cash equivalents	838	(7,802)
Cash and cash equivalents at end of period	$4,075	$9,002

Operating Activities

Operating activities during the first nine months of 2003 provided $30 million more cash than during 2002 largely due to the year-over-year increase in net income of $10 million and a $51 million increase in the change in mark-to-market of risk management contracts offset by a $43 million decrease in accrued taxes.

Investing Activities

Cash flows used for investing activities during the first nine months of 2003 were $107 million compared to $91 million during 2002. The primary reason for the year-over-year variance was a construction expenditures increase of $16 million. 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 the nine months ended September 30, 2003 used $6 million more than 2002 primarily due to dividends paid on common stock as none were paid in 2002.

Financing Activity

Long-term debt issuances and retirements (using short-term debt) during the first nine months of 2003 were:

Issuances

None

Retirements

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
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

Significant Factors

Nuclear Plant Outages

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 2003 and Unit 2 returned to service in June 2003 following completion of a scheduled refueling outage.

Federal EPA Complaint and Notice of Violation

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), we are involved in litigation regarding generating plant emissions under the Clean Air Act. The Federal EPA and a number of states alleged I&M, certain affiliated companies and eleven unaffiliated utilities made modifications to generating units at coal-fired generating plants in violation of the Clean Air Act. The Federal EPA filed complaints against us in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20 year period.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the Clear Air Act proceedings and is 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. In the event 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. See Note 5 for further discussion.

NOx Reductions

The Federal EPA issued a NOx Rule and adopted a revised rule (the Section 126 Rule) under the Clean Air Act requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. The compliance date for the rules is May 31, 2004.

We are installing combustion control technology to reduce NOx emissions on certain units to comply with these rules. Our estimates indicate that compliance with the rules could result in required capital expenditures of approximately $39 million. The actual cost to comply could be significantly different than the estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital or operating costs for additional pollution control equipment are recovered from customers, these costs would adversely affect future results of operations, cash flows and possibly financial condition. See Note 5 for further discussion.

Critical Accounting Policies

See "Registrants' Combined Management's Discussion and Analysis of Financial Condition, Accounting Policies and Other Matters - Critical Accounting Policies" in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Risk management policies and procedures are instituted and administered at the AEP consolidated level for all subsidiary registrants. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about the risk management activities' effect on this specific registrant.

Roll-Forward of MTM Risk Management Contract Net Assets

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

Roll-Forward of MTM Risk Management Contract Net Assets

Nine Months Ended September 30, 2003 (in thousands)	
Domestic Power	
Beginning Balance December 31, 2002	$70,861
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(19,968)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	164
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of 98-10 Rescission	(4,861)
Changes in Fair Value of Risk Management Contracts (d)	(928)
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(9,928)

Total MTM Risk Management Contract Net Assets	35,340
Net Non-Trading Related Derivative Contracts	985
Net Fair Value of Risk Management and Derivative Contracts September 30, 2003	$36,325

(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)"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.
(e)"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.

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:
o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 September 30, 2003

	Remainder 2003	2004	2005	2006	2007	After 2007	Total
			(in thousands)				
Prices Actively Quoted - Exchange Traded Contracts	$(180)	$32	$(164)	$-	$-	$-	$(312)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	812	9,067	3,827	3,356	795	-	17,857
Prices Based on Models and Other Valuation Methods (b)	821	2,790	1,998	2,416	2,664	7,106	17,795
Total	$1,453	$11,889	$5,661	$5,772	$3,459	$7,106	$35,340

(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" if there is 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.

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 Other Comprehensive Income (Loss) Activity

Nine Months Ended September 30, 2003

	Domestic Power
(in thousands)	
Accumulated OCI, December 31, 2002	$(286)
Changes in Fair Value (a)	526
Reclassifications from OCI to Net Income (b)	295
Accumulated OCI Derivative Gain (Loss) September 30, 2003	$535

(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 OCI 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 Accumulated OCI expected to be reclassified to earnings during the next twelve months is a $933 thousand gain.

Credit Risk

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

VaR Associated with Energy Trading Contracts

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

September 30, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$494	$1,402	$646	$140	$927	$2,840	$1,016	$206

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2003	2002	2003	2002
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$356,003	$353,897	$1,022,296	$982,565
Sales to AEP Affiliates	67,001	60,517	196,212	153,127
TOTAL	423,004	414,414	1,218,508	1,135,692
OPERATING EXPENSES				
Fuel for Electric Generation	67,588	65,904	206,445	173,223
Purchased Electricity for Resale	9,058	6,706	22,375	17,386
Purchased Electricity from AEP Affiliates	68,653	59,846	207,904	176,463
Other Operation	109,106	108,457	319,019	340,556
Maintenance	38,518	41,668	112,480	112,291
Depreciation and Amortization	43,453	42,081	130,020	125,817
Taxes Other Than Income Taxes	15,698	16,698	44,668	52,794
Income Taxes	14,688	16,050	41,136	29,930
TOTAL	366,762	357,410	1,084,047	1,028,460
OPERATING INCOME	56,242	57,004	134,461	107,232
Nonoperating Income	19,335	17,899	36,240	56,452
Nonoperating Expenses	18,130	12,875	43,965	35,285
Nonoperating Income Tax Expense (Credit)	821	2,999	(4,479)	3,887
Interest Charges	19,510	23,717	64,603	70,648
Net Income Before Cumulative Effect of Accounting Change	37,116	35,312	66,612	53,864
Cumulative Effect of Accounting Change (Net of Tax)	-	-	(3,160)	-
NET INCOME	37,116	35,312	63,452	53,864
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	118	1,145	2,390	3,453
EARNINGS APPLICABLE TO COMMON STOCK	$36,998	$34,167	$61,062	$50,411

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 COMMON SHAREHOLDER'S EQUITY
AND COMPREHENSIVE INCOME
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 2002	$56,584	$733,216	$74,605	$(3,835)	$860,570
Capital Contributions from Parent Company		125,000			125,000
Preferred Stock Dividends			(3,352)		(3,352)
Capital Stock Expense		310	(100)		210
					982,428
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Interest Rate Hedge				3,835	3,835
Unrealized Gain on Cash Flow Power Hedges				349	349
NET INCOME			53,864		53,864
TOTAL COMPREHENSIVE INCOME					58,048
SEPTEMBER 30, 2002	$56,584	$858,526	$125,017	$349	$1,040,476
JANUARY 1, 2003	$56,584	$858,560	$143,996	$(40,487)	$1,018,653
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(2,289)		(2,289)
Capital Stock Expense		101	(101)		-
					986,364
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				821	821
NET INCOME			63,452		63,452
TOTAL COMPREHENSIVE INCOME					64,273
SEPTEMBER 30, 2003	$56,584	$858,661	$175,058	$(39,666)	$1,050,637

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,872,210	$2,768,463
Transmission	992,046	971,599
Distribution	947,186	921,835
General (including nuclear fuel)	269,550	220,137
Construction Work in Progress	163,884	147,924
TOTAL	5,244,876	5,029,958
Accumulated Depreciation and Amortization	2,719,346	2,568,604
TOTAL - NET	2,525,530	2,461,354
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	945,372	870,754
Long-term Risk Management Assets	51,574	83,265
Other Property and Investments	110,921	120,941
CURRENT ASSETS		
Cash and Cash Equivalents	4,075	3,237
Advances to Affiliates	-	191,226
Accounts Receivable:		
Customers	55,735	67,333
Affiliated Companies	84,914	122,489
Miscellaneous	19,420	30,468
Allowance for Uncollectible Accounts	(568)	(578)
Fuel	25,014	32,731
Materials and Supplies	105,757	95,552
Risk Management Assets	36,271	68,148
Prepayments and Other	13,503	18,410
TOTAL	344,121	629,016
Regulatory Assets	265,205	348,212
Deferred Charges	51,709	73,649
TOTAL ASSETS	$4,294,432	$4,587,191

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2003 and December 31, 2002
(Unaudited)

	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	858,661	858,560
Accumulated Other Comprehensive Income (Loss)	(39,666)	(40,487)
Retained Earnings	175,058	143,996
Total Common Shareholder's Equity	1,050,637	1,018,653
Cumulative Preferred Stock - Not Subject to Mandatory Redemption	8,101	8,101
Liability for Cumulative Preferred Stock - Subject to Mandatory Redemption	63,445	64,945
Long-term Debt	1,188,337	1,587,062
TOTAL	2,310,520	2,678,761
OTHER NONCURRENT LIABILITIES		
Asset Retirement Obligations	543,688	-
Nuclear Decommissioning	-	620,672
Other	128,957	138,965
TOTAL	672,645	759,637
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	180,000	30,000
Advances from Affiliates	13,929	-
Accounts Payable:		
General	81,366	125,048
Affiliated Companies	41,666	93,608
Taxes Accrued	43,415	71,559
Interest Accrued	23,674	21,481
Risk Management Liabilities	23,541	48,568
Other	111,791	101,051
TOTAL	519,382	491,315
Deferred Income Taxes	316,515	356,197
Deferred Investment Tax Credits	92,205	97,709
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	71,105	73,885
Long-term Risk Management Liabilities	27,979	32,261
Deferred Credits and Regulatory Liabilities	284,081	97,426
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$4,294,432	$4,587,191

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$63,452	$53,864
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	3,160	-
Depreciation and Amortization	130,020	125,881
Deferral of Incremental Nuclear Refueling Outage Expenses, Net	(4,049)	(38,103)
Unrecovered Fuel and Purchased Power Costs	28,126	28,126
Amortization of Nuclear Outage Costs	30,000	30,000
Deferred Income Taxes	(17,767)	(6,885)
Deferred Investment Tax Credits	(5,504)	(5,534)
Mark-to-Market of Risk Management Contracts	30,661	(20,358)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	60,211	(115,027)
Fuel, Materials and Supplies	(2,488)	1,155
Accounts Payable	(95,624)	79,400
Taxes Accrued	(28,144)	14,734
Rent Accrued - Rockport Plant Unit 2	18,464	18,464
Change in Other Assets	(15,379)	(31,715)
Change in Other Liabilities	(4,121)	27,458
Net Cash Flows From Operating Activities	191,018	161,460
INVESTING ACTIVITIES		
Construction Expenditures	(108,201)	(92,387)
Other	1,655	1,027
Net Cash Flows Used For Investing Activities	(106,546)	(91,360)
FINANCING ACTIVITIES		
Capital Contributions from Parent	-	125,000
Issuance of Long-term Debt	-	49,648
Retirement of Cumulative Preferred Stock	(1,500)	(424)
Retirement of Long-term Debt	(255,000)	(250,000)
Change in Advances to/from Affiliates, Net	205,155	1,214
Dividends Paid on Common Stock	(30,000)	-
Dividends Paid on Cumulative Preferred Stock	(2,289)	(3,340)
Net Cash Flows Used For Financing Activities	(83,634)	(77,902)
Net Increase (Decrease) in Cash and Cash Equivalents	838	(7,802)
Cash and Cash Equivalents at Beginning of Period	3,237	16,804
Cash and Cash Equivalents at End of Period	$4,075	$ 9,002

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $59,359,000 and $63,987,000 and for income taxes was $79,880,000 and $21,225,000 in 2003 and 2002, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Net Income for the third quarter of 2003 increased $0.5 million from the corresponding quarter in 2002 due to improved earnings from system sales and transmission revenues. Net Income for the nine months ended September 30, 2003 decreased $1 million from the prior year due to the loss from the Cumulative Effect of Accounting Change of $1 million (see Note 2). Income Before Cumulative Effect of Accounting Change for the first nine months of 2003 was essentially flat compared to the prior year period as improved earnings from system sales and transmission revenues were offset by decreased net nonoperating income. As a member of the AEP Power Pool, we share in the revenues and costs of marketing and activities conducted on our behalf by the AEP Power Pool.

Third Quarter 2003 Compared to Third Quarter 2002

Operating Income

Operating Income for the third quarter of 2003 increased $2 million primarily due to:

o Increases in system sales and transmission revenues of $5 million and an increase in gains from risk management activities of $3 million.
o A decrease in Income Taxes of $2 million primarily due to state income tax accrual adjustments.

The increases in Operating Income were partially offset by:

o A decline in retail sales of $2 million in the third quarter of 2003 resulting from decreased residential sales reflecting the mild weather conditions, despite a rate increase to recover the cost of emission control equipment (see Note 3). Cooling degree days were down 32% for the third quarter of 2003 compared to the prior year quarter. Lower industrial sales reflecting the continued weak economy also contributed to the decline in retail sales.
o An increase in purchased power of $4 million necessary to support system sales.
o An increase in Depreciation and Amortization of $2 million reflecting the completion and implementation of new capital projects in the third quarter of 2003, as well as the implementation of the SCR technology at the Big Sandy plant in the second quarter of 2003.

Other Impacts on Earnings

Nonoperating Income for the third quarter of 2003 was relatively flat. Nonoperating Income Tax Expense for the quarter increased $1 million for the third quarter of 2003 primarily due to changes in certain book versus tax differences accounted for on a flow-through basis.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Operating Income

Operating Income for the nine months ended September 30, 2003 increased $8 million primarily due to:

o An increase in system sales and transmission revenues of $12 million and an increase in gains from risk management activities of $8 million.
o A decrease in Other Operation expense of $2 million from 2002 due to decreased engineering expenses and lower employee benefit expenses.

The increases in Operating Income were partially offset by:

o A decline in industrial sales of $4 million reflecting the continued weak economy.
o An increase in Depreciation and Amortization of $4 million reflecting the depreciation on the capital projects implemented in 2003 as discussed above, as well as the implementation of an enterprise-wide software application in mid-2002.
o Increases in Purchased Electricity from AEP Affiliates of $16 million necessary to support sales during the Big Sandy plant shutdown for the NOx reduction upgrades. The outage resulted in a decrease in net generation leading to a $6 million decrease in fuel expense that partly offset the increased purchased power expense. In addition, energy purchases increased from the Rockport Plant based on plant availability, as required by the unit power agreement with AEGCo, an affiliated company. The unit power agreement with AEGCo provides for our purchase of 15% of the total output of the two unit 2,600-MW capacity Rockport Plant.

Other Impacts on Earnings

Nonoperating Income for the first nine months of 2003 decreased $9 million primarily due to reduced gains from risk management activities compared to the prior year. Nonoperating Income Tax Expense for the first nine months of 2003 decreased $2 million primarily due to a decrease in pre-tax nonoperating book income.

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change of $1 million is due to the implementation of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

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

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

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The completion of this review was a culmination of ratings action started during 2002.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2003 were:

Issuances

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$75	5.625	2032

Retirements

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Junior Debentures	$40	8.72	2025

Intercompany Retirements of Debt Due to AEP

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Notes Payable	$15	4.336	2003

Significant Factors

NOx Reductions

The Federal EPA issued a NOx Rule and adopted a revised rule (the Section 126 Rule) under the Clean Air Act requiring substantial reductions in NOx emissions in a number of eastern states, including Kentucky where our generating plant is located. The compliance date for the rules is May 31, 2004.

In May 2003, selective catalytic reduction (SCR) technology and other combustion control technology to reduce NOx emissions at our Big Sandy plant commenced operation to comply with these rules.

The capital expenditures for the SCR and other combustion control technology totaled $179 million through September 30, 2003. In 2003, the KPSC granted recovery of approximately $18 million annually (see Note 3). See Note 5 for further discussion of emissions control technology.

RTO Formation

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), 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 the transmission system to RTOs. Further, legislation in certain states in which AEP subsidiaries operate 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, we filed with KPSC for approval of our plan to transfer functional control of our transmission assets to PJM. In July 2003, the KPSC ruled, in part, that we had failed to prove the benefit of our PJM RTO membership to Kentucky retail customers and denied our request for approval of transfer of functional control to PJM. In August 2003, AEP sought and received rehearing of the KPSC's order, allowing us to file additional evidence in this proceeding.

We are 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 (see Note 3).

Critical Accounting Policies

See "Registrants' Combined Management's Discussion and Analysis of Financial Condition, Accounting Policies and Other Matters - Critical Accounting Policies" in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Risk management policies and procedures are instituted and administered at the AEP consolidated level for all subsidiary registrants. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about the risk management activities' effect on this specific registrant.

Roll-Forward of MTM Risk Management Contract Net Assets

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

Roll-Forward of MTM Risk Management Contract Net Assets

	Nine Months Ended September 30, 2003 (in thousands)
Domestic Power	
Beginning Balance December 31, 2002	$24,998
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(7,926)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	60
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of 98-10 Rescission	(1,744)
Changes in Fair Value of Risk Management Contracts (d)	601
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(2,685)
Total MTM Risk Management Contract Net Assets	13,304
Net Non-Trading Related Derivative Contracts	361
Net Fair Value of Risk Management and Derivative Contracts September 30, 2003	$13,665

(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)"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.

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

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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

o 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 September 30, 2003

	Remainder 2003	2004	2005	2006	2007	After 2007	Total
			(in thousands)				
Prices Actively Quoted - Exchange Traded Contracts	$(66)	$12	$(60)	$-	$-	$-	$(114)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	288	3,322	1,411	1,237	293	-	6,551
Prices Based on Models and Other Valuation Methods (b)	480	1,160	736	890	982	2,619	6,867
Total	$702	$4,494	$2,087	$2,127	$1,275	$2,619	$13,304

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" if there is 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.

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 Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2003

	Domestic Power	Interest Rate	Consolidated
		(in thousands)	
Accumulated OCI, December 31, 2002	$(103)	$425	$322
Changes in Fair Value (a)	192	-	192
Reclassifications from OCI to Net Income (b)	108	(65)	43
Accumulated OCI Derivative Gain (Loss) September 30, 2003	$197	$360	$557

(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 OCI 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 Accumulated OCI expected to be reclassified to earnings during the next twelve months is a $430 thousand gain.

Credit Risk

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

VaR Associated with Energy Trading Contracts

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

September 30, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$182	$517	$238	$51	$333	$1,019	$364	$74

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2003	2002	2003	2002
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$93,500	$87,720	$281,755	$264,154
Sales to AEP Affiliates	10,193	10,091	29,496	25,006
TOTAL	103,693	97,811	311,251	289,160
OPERATING EXPENSES				
Fuel for Electric Generation	19,608	19,747	52,994	59,084
Purchased Electricity for Resale	738	24	719	26
Purchased Electricity from AEP Affiliates	34,723	31,440	108,289	92,747
Other Operation	12,519	12,932	36,351	37,902
Maintenance	6,671	7,168	20,597	19,795
Depreciation and Amortization	10,693	8,330	28,653	24,856
Taxes Other Than Income Taxes	2,300	1,904	6,742	6,407
Income Taxes	3,344	5,147	13,011	12,190
TOTAL	90,596	86,692	267,356	253,007
OPERATING INCOME	13,097	11,119	43,895	36,153
Nonoperating Income (Loss)	1,329	1,712	(1,636)	6,907
Nonoperating Expenses	212	707	554	701
Nonoperating Income Tax Expense (Credit)	370	(801)	(1,114)	929
Interest Charges	7,343	6,931	21,202	19,944
Income Before Cumulative Effect of Accounting Change	6,501	5,994	21,617	21,486
Cumulative Effect of Accounting Change (Net of Tax)	-	-	(1,134)	-
NET INCOME	$6,501	$5,994	$20,483	$21,486

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

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
AND COMPREHENSIVE INCOME
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 2002	$50,450	$158,750	$48,833	$(1,903)	$256,130
Common Stock Dividends			(21,132)		(21,132)
TOTAL					234,998
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				1,519	1,519
NET INCOME			21,486		21,486
TOTAL COMPREHENSIVE INCOME					23,005
SEPTEMBER 30, 2002	$50,450	$158,750	$49,187	$(384)	$258,003
JANUARY 1, 2003	$50,450	$208,750	$48,269	$(9,451)	$298,018
Common Stock Dividends			(16,448)		(16,448)
TOTAL					281,570
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				235	235
NET INCOME			20,483		20,483
TOTAL COMPREHENSIVE INCOME					20,718
SEPTEMBER 30, 2003	$50,450	$208,750	$52,304	$(9,216)	$302,288

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$457,231	$275,121
Transmission	380,112	373,639
Distribution	422,127	414,281
General	67,071	67,449
Construction Work in Progress	17,067	165,129
TOTAL	1,343,608	1,295,619
Accumulated Depreciation and Amortization	401,887	397,304
TOTAL - NET	941,721	898,315
Other Property and Investments	6,684	6,904
Long-term Risk Management Assets	19,006	29,871
CURRENT ASSETS		
Cash and Cash Equivalents	760	2,304
Accounts Receivable:		
Customers	17,395	22,044
Affiliated Companies	14,281	23,802
Miscellaneous	4,637	2,889
Allowance for Uncollectible Accounts	(757)	(192)
Fuel	9,702	10,817
Materials and Supplies	17,855	16,127
Accrued Utility Revenues	4,963	5,301
Accrued Tax Benefit	-	1,253
Risk Management Assets	13,196	24,320
Prepayments and Other	2,825	2,127
TOTAL	84,857	110,792
Regulatory Assets	105,039	101,976
Deferred Charges	14,110	16,818
TOTAL ASSETS	$1,171,417	$1,164,676

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
CAPATALIZATION AND LIABILITIES
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - $50 Par Value:		
Authorized - 2,000,000 Shares		
Outstanding - 1,009,000 Shares	$50,450	$50,450
Paid-in Capital	208,750	208,750
Accumulated Other Comprehensive Income (Loss)	(9,216)	(9,451)
Retained Earnings	52,304	48,269
Total Common Shareholder's Equity	302,288	298,018
Long-term Debt:		
Nonaffiliated	427,578	391,632
Affiliated	60,000	60,000
Total Long-term Debt	487,578	451,632
TOTAL	789,866	749,650
Other Noncurrent Liabilities	25,228	27,319
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Affiliated	-	15,000
Advances from Affiliates	42,195	23,386
Accounts Payable:		
General	28,019	46,515
Affiliated Companies	22,911	44,035
Customer Deposits	9,452	8,048
Interest Accrued	8,949	6,471
Taxes Accrued	202	-
Risk Management Liabilities	8,256	17,803
Other	11,353	14,322
TOTAL	131,337	175,580
Deferred Income Taxes	197,121	178,313
Deferred Investment Tax Credits	8,284	9,165
Long-term Risk Management Liabilities	10,281	11,488
Regulatory Liabilities and Deferred Credits	9,300	13,161
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,171,417	$1,164,676

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$20,483	$21,486
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	1,134	-
Depreciation and Amortization	28,653	24,856
Deferred Income Taxes	16,020	7,461
Deferred Investment Tax Credits	(880)	(886)
Deferred Fuel Costs, Net	(772)	2,081
Mark-to-Market of Risk Management Contracts	9,950	(13,161)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	12,987	(13,559)
Fuel, Materials and Supplies	(613)	484
Accrued Utility Revenues	338	(1,382)
Accounts Payable	(39,620)	20,715
Taxes Accrued	1,455	(3,360)
Change in Other Assets	(2,792)	(2,154)
Change in Other Liabilities	(61)	12,238
Net Cash Flows From Operating Activities	46,282	54,819
INVESTING ACTIVITIES		
Construction Expenditures	(71,154)	(100,677)
Proceeds from Sales of Property and Other	967	182
Net Cash Flow Used for Investing Activities	(70,187)	(100,495)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	75,000	-
Issuance of Long-term Debt - Affiliated	-	123,843
Retirement of Long-term Debt - Nonaffiliated	(40,000)	(84,500)
Retirement of Long-term Debt - Affiliated	(15,000)	-
Change in Advances to/from Affiliates, Net	18,809	26,391
Dividends Paid	(16,448)	(21,132)
Net Cash Flows From Financing Activities	22,361	44,602
Net Decrease in Cash and Cash Equivalents	(1,544)	(1,074)
Cash and Cash Equivalents at Beginning of Period	2,304	1,947
Cash and Cash Equivalents at End of Period	$760	$873

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $17,925,000 and $19,560,000 in 2003 and 2002, respectively. Cash (received) paid for income taxes was $(7,605,000) and $7,025,000 in 2003 and 2002, respectively. There were no noncash acquisitions under capital lease in 2003. Noncash acquisitions under capital leases in 2002 were $22,000.

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Effective July 1, 2003, we consolidated JMG Funding, LP (JMG) as a result of the implementation of FIN 46. See Note 2, "New Accounting Pronouncements and Cumulative Effect of Accounting Changes," and Note 8, "Leases," for further discussion of the effects of FIN 46.

Results of Operations

Net Income for the quarter decreased $10 million due primarily to mild summer weather and increased interest charges related to new issuances of debt. Net Income increased $120 million year-to-date including $125 million Cumulative Effect of Accounting Changes in the first quarter of 2003 (see Note 2). Net Income Before Cumulative Effect of Accounting Changes decreased $5 million year-to-date primarily due to decreased revenues from risk management activities. We, as a member of the AEP Power Pool, share in the revenues and the costs of the AEP Power Pool's wholesale sales to neighboring utilities and risk management transactions.

Third Quarter 2003 Compared to Third Quarter 2002

Operating Income

Operating Income decreased $3 million for the third quarter primarily due to the following:

o Retail revenues decreased $10 million due primarily to milder weather during the third quarter 2003 and economic pressures on industrial customers. Cooling degree days were 36% less in the third quarter this year compared with the third quarter of last year. Industrial revenues dropped 5% from the third quarter of last year.
o Risk management income decreased $13 million due primarily to unfavorable market conditions and reduced activity.
o Third quarter Fuel for Electric Generation expense increased $7 million due primarily to an increase of 10% in MWHs generated, which was sold to the AEP Power Pool.
o Maintenance expense increased $7 million due primarily to boiler overhaul work coupled with increased expense in maintaining overhead lines.

The decrease in Operating Income was partially offset by the following:

o Affiliated sales increased $34 million. The increase is the result of optimizing our generation capacity and selling our excess generated power to the AEP Power Pool.
o Income Taxes decreased $7 million primarily due to a decrease in pre-tax operating book income offset in part by changes in certain book versus tax differences accounted for on a flow-through basis.

Other Impacts of Earnings

Nonoperating Income increased $9 million for the third quarter due primarily to the reduction in accruals for costs associated with coal companies sold prior to 2003.

Interest charges increased $15 million for the third quarter due primarily to the replacement of lower cost floating-rate short-term debt with higher cost fixed-rate longer-term debt.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Operating Income

Operating Income increased $31 million year to date primarily due to the following:

o Revenues from non-affiliated system sales increased $25 million and affiliated sales increased $90 million. The increase in non-affiliated system sales is the result of the increase in volume of AEP Power Pool Sales allocated to us for the first nine months of 2003. The increase in affiliated sales is the result of optimizing our generation capacity and selling our excess generated power to the AEP Power Pool.
o Other Operation expenses decreased due primarily to a $7 million pre-tax adjustment to the workers' compensation reserve for coal companies sold in July 2001 and a $4 million decrease primarily due to a decrease in OPCo's portion of the total AEP Transmission Equalization payments.

The increase in Operating Income was partially offset by the following:

o Year-to-date Fuel for Electric Generation expense increased $22 million due primarily to an increase of 8.5% in MWHs generated.
o Maintenance expense increased $37 million due primarily to boiler overhaul work coupled with increased expense in maintaining overhead lines due to storm damage in southern Ohio.
o Purchased Electricity from AEP Affiliates increased $16 million as a result of an increased volume of purchases from the AEP Power Pool for the first nine months of 2003.

Other Impacts on Earnings

Nonoperating Income decreased $22 million year-to-date due primarily to lower margins for risk management activities outside of AEP's traditional marketing area reflecting reduced demand and AEP's plan to exit risk management activities in areas outside of its traditional market area.

Interest charges increased $14 million due primarily to the replacement of lower cost floating-rate short-term debt with higher cost fixed-rate longer-term debt.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

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

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

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and its subsidiaries senior unsecured ratings from BBB+ to BBB along with the first mortgage bonds of AEP subsidiaries.

Cash Flow

Cash flows for nine months ended September 30, 2003 and 2002 were as follows:

	2003	2002
	(in thousands)	
Cash and cash equivalents at beginning of period	$5,285	$8,848
Cash flow from (used for):		
Operating activities	232,482	446,138
Investing activities	(160,244)	(218,813)
Financing activities	(70,810)	(228,221)
Net increase (decrease) in cash and cash equivalents	1,428	(896)
Cash and cash equivalents at end of period	$6,713	$7,952

Operating Activities

Cash flow from operating activities for the nine months ended September 30, 2003 decreased $214 million as they were adversely impacted primarily by significant reductions of accounts payable balances partially associated with a wind down of risk management activities in the current year.

Investing Activities

Cash flows used for investing activities were reduced in the current year due primarily to a $60 million decrease in construction expenditures.

Financing Activities

Cash flow used for financing activities for the first nine months of 2003 used $157 million less than the first nine months of 2002 primarily due to:

o Retirement and restructuring of our long-term and short-term debt during 2003. We retired $300 million of Long-term Debt to Affiliated Companies and $275 million of Short-term Debt to Affiliated Companies with the proceeds of two Senior Unsecured Notes at $250 million each.
o We issued two series of Senior Unsecured Notes, each in the amount of $225 million each in July 2003.
o The change in Advances to/from Affiliates, net decreased $133 million from prior period.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2003 were:

Issuances

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$250	5.50	2013
Senior Unsecured Notes	250	6.60	2033
Senior Unsecured Notes	225	4.85	2014
Senior Unsecured Notes	225	6.375	2033

Retirements

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
First Mortgage Bonds	$30	6.75	2003

Intercompany Retirements of Debt Due to AEP

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Notes Payable	$240	6.501	2006
Notes Payable	60	4.336	2003

Significant Factors

Federal EPA Complaint and Notice of Violation

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), we are involved in litigation regarding generating plant emissions under the Clean Air Act. The Federal EPA and a number of states alleged OPCo, certain affiliated companies and eleven unaffiliated utilities made modifications to generating units at coal-fired generating plants in violation of the Clean Air Act. The Federal EPA filed complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20 year period.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the Clear Air Act proceedings and is 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. In the event 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. See Note 5 for further discussion.

NOx Reductions

The Federal EPA issued a NOx Rule and adopted a revised rule (the Section 126 Rule) under the Clean Air Act requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. The compliance date for the rules is May 31, 2004.

We are installing selective catalytic reduction (SCR) technology and other combustion control technology to reduce NOx emissions on certain units to comply with these rules.

Our estimates indicate that compliance with the rules could result in required capital expenditures in a range of $531 million to $860 million. The actual cost to comply could be significantly different than the estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital or operating costs for additional pollution control equipment are recovered from customers, these costs would adversely affect future results of operations, cash flows and possibly financial condition. See Note 5 for further discussion.

Critical Accounting Policies

See "Registrants' Combined Management's Discussion and Analysis of Financial Condition, Accounting Policies and Other Matters - Critical Accounting Policies" in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Risk management policies and procedures are instituted and administered at the AEP consolidated level for all subsidiary registrants. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about the risk management activities' effect on this specific registrant.

Roll-Forward of MTM Risk Management Contract Net Assets

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

Roll-Forward of MTM Risk Management Contract Net Assets

Nine Months Ended September 30, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$94,106
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(36,790)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	199
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of 98-10 Rescission	(4,159)
Changes in Fair Value of Risk Management Contracts (d)	(3,694)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	-
Total MTM Risk Management Contract Net Assets	49,662
Net Non-Trading Related Derivative Contracts	1,207
Net Fair Value of Risk Management and Derivative Contracts September 30, 2003	$50,869

(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)"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.
(e)"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.

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:
o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 September 30, 2003

	Remainder 2003	2004	2005	2006	2007	After 2007	Total
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(219)	$40	$(200)	$-	$-	$-	$(379)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	4,218	13,368	4,668	4,093	969	-	27,316
Prices Based on Models and Other Valuation Methods (b)	1,588	3,839	2,437	2,946	3,249	8,666	22,725
Total	$5,587	$17,247	$6,905	$7,039	$4,218	$8,666	$49,662

(a)"Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" if there is 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.

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).

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

Total Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2003

	Domestic Power	Foreign Currency	Consolidated
		(in thousands)	
Accumulated OCI, December 31, 2002	$(354)	$(384)	$(738)
Changes in Fair Value (a)	645	-	645
Reclassifications from OCI to Net Income (b)	361	10	371
Accumulated OCI Derivative Gain (Loss)			

September 30, 2003	$652	$(374)	$278
	======	======	======

(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 OCI 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 Accumulated OCI expected to be reclassified to earnings during the next twelve months is a $1,125 thousand gain.

Credit Risk

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

VaR Associated with Energy Trading Contracts

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

September 30, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$602	$1,710	$788	$170	$1,150	$3,521	$1,259	$255

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended 2003	Three Months Ended 2002	Nine Months Ended 2003	Nine Months Ended 2002
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$418,083	$444,298	$1,256,862	$1,251,288
Sales to AEP Affiliates	147,235	113,276	438,473	348,303
TOTAL	565,318	557,574	1,695,335	1,599,591
OPERATING EXPENSES				
Fuel for Electric Generation	155,222	148,480	462,316	439,913
Purchased Electricity for Resale	15,219	15,841	52,064	49,042
Purchased Electricity from AEP Affiliates	23,693	20,375	70,905	54,867
Other Operation	92,376	94,893	269,998	290,982
Maintenance	38,598	32,011	127,466	90,956
Depreciation and Amortization	67,365	62,144	189,140	185,941
Taxes Other Than Income Taxes	45,582	46,341	132,350	135,472
Income Taxes	33,465	40,279	118,597	110,446
TOTAL	471,520	460,364	1,422,836	1,357,619
OPERATING INCOME	93,798	97,210	272,499	241,972
Nonoperating Income	20,567	11,157	21,350	43,057
Nonoperating Expenses	8,840	6,241	26,565	17,501
Nonoperating Income Tax Expense (Credit)	1,646	3,638	(1,446)	7,986
Interest Charges	33,512	18,230	73,736	59,885
Income Before Cumulative Effect of Accounting Changes	70,367	80,258	194,994	199,657
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	124,632	-
NET INCOME	70,367	80,258	319,626	199,657
Preferred Stock Dividend Requirements	286	315	915	944
EARNINGS APPLICABLE TO COMMON STOCK	$70,081	$79,943	$318,711	$198,713

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

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY AND
COMPREHENSIVE INCOME
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 2002	$321,201	$462,483	$401,297	$(196)	$1,184,785
Common Stock Dividends			(97,746)		(97,746)
Preferred Stock Dividends			(944)		(944)
					1,086,095
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss)					
Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				242	242
NET INCOME			199,657		199,657
TOTAL COMPREHENSIVE INCOME					199,899
SEPTEMBER 30, 2002	$321,201	$462,483	$502,264	$46	$1,285,994
JANUARY 1, 2003	$321,201	$462,483	$522,316	$(72,886)	$1,233,114
Common Stock Dividends			(125,800)		(125,800)
Preferred Stock Dividends			(915)		(915)
Capital Stock Expense		1			1
TOTAL					1,106,400
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss)					
Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				1,016	1,016
Minimum Pension Liability				5,625	5,625
NET INCOME			319,626		319,626
TOTAL COMPREHENSIVE INCOME					326,267
SEPTEMBER 30, 2003	$321,201	$462,484	$715,227	$(66,245)	$1,432,667

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$4,013,884	$3,116,825
Transmission	928,373	905,829
Distribution	1,146,589	1,114,600
General	239,523	260,153
Construction Work in Progress	136,462	288,419
Total	6,464,831	5,685,826
Accumulated Depreciation and Amortization	2,548,845	2,566,828
TOTAL - NET	3,915,986	3,118,998
Other Property and Investments	52,907	61,686
Long-term Risk Management Assets	62,885	103,230
CURRENT ASSETS		
Cash and Cash Equivalents	6,713	5,285
Advances to Affiliates	142,894	-
Accounts Receivable:		
Customers	78,341	95,100
Affiliated Companies	92,972	124,244
Miscellaneous	21,381	19,281
Allowance for Uncollectible Accounts	(887)	(909)
Fuel	81,926	87,409
Materials and Supplies	86,347	85,379
Risk Management Assets	49,332	92,108
Prepayments and Other	26,198	12,083
TOTAL	585,217	519,980
Regulatory Assets	512,890	568,641
Deferred Charges and Other Assets	49,571	84,497
TOTAL	$5,179,456	$4,457,032

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - No Par Value:		
Authorized - 40,000,000 Shares		
Outstanding - 27,952,473 Shares	$321,201	$321,201
Paid-in Capital	462,484	462,483
Accumulated Other Comprehensive Income (Loss)	(66,245)	(72,886)
Retained Earnings	715,227	522,316
Total Common Shareholder's Equity	1,432,667	1,233,114
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,645	16,648
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	8,350	8,850
Long-term Debt:		
Nonaffiliated	1,819,176	677,649
Affiliated	-	240,000
Total Long-term Debt	1,819,176	917,649
TOTAL CAPITALIZATION	3,276,838	2,176,261
Minority Interest	16,918	-
Other Noncurrent Liabilities	209,808	227,689
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	268,919	89,665
Long-term Debt Due Within One Year - Affiliated	-	60,000
Short-term Debt - General	28,651	-
Short-term Debt - Affiliates	-	275,000
Advances from Affiliates	-	129,979
Accounts Payable - General	97,323	170,563
Accounts Payable - Affiliated Companies	67,516	145,718
Customer Deposits	16,548	12,969
Taxes Accrued	94,096	111,778
Interest Accrued	33,661	18,809
Obligations Under Capital Leases	9,509	14,360
Risk Management Liabilities	27,332	61,839
Other	69,846	80,608
TOTAL	713,401	1,171,288
Deferred Income Taxes	886,015	794,387
Deferred Investment Tax Credits	16,460	18,748
Long-term Risk Management Liabilities	34,016	39,702
Deferred Credits	26,000	28,957
Commitments and Contingencies (Note 5)		
TOTAL	$5,179,456	$4,457,032

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$319,626	$199,657
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	(124,632)	-
Depreciation and Amortization	189,140	185,941
Deferred Income Taxes	4,139	95
Mark-to-Market of Risk Management Contracts	40,283	(34,477)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	45,966	14,289
Fuel, Materials and Supplies	4,515	10,333
Accrued Utility Revenues	(8,167)	(2,677)
Prepayments and Other	(9,030)	(11,330)
Accounts Payable	(215,012)	20,011
Customer Deposits	3,579	9,101
Taxes Accrued	(17,682)	37,370
Interest Accrued	9,516	1,870
Deferred Property Taxes	46,491	45,275
Change in Other Assets	(10,895)	(18,513)
Change in Other Liabilities	(45,355)	(10,807)
Net Cash Flows From Operating Activities	232,482	446,138
INVESTING ACTIVITIES		
Construction Expenditures	(163,864)	(224,257)
Proceeds from Sale of Property and Other	3,620	5,444
Net Cash Flows Used For Investing Activities	(160,244)	(218,813)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	950,000	-
Capital Contribution from Parent	(17,910)	-
Change in Advances to/from Affiliates, Net	(272,872)	(139,531)
Change in Short-term Debt	2,039	-
Change in Short-term Debt - Affiliates	(275,000)	150,000
Retirement of Long-term Debt - Nonaffiliated	(29,850)	(140,000)
Retirement of Long-term Debt - Affiliated	(300,000)	-
Retirement of Cumulative Preferred Stock	(502)	-
Dividends Paid on Common Stock	(125,800)	(97,746)
Dividends Paid on Cumulative Preferred Stock	(915)	(944)
Net Cash Flows Used For Financing Activities	(70,810)	(228,221)
Net Increase (Decrease) in Cash and Cash Equivalents	1,428	(896)
Cash and Cash Equivalents at Beginning of Period	5,285	8,848
Cash and Cash Equivalents at End of Period	$6,713	$7,952

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $57,517,000 and $56,864,000 and for income taxes was $74,858,000 and $29,981,000 in 2003 and 2002, respectively. Noncash acquisitions under capital leases were $98,000 in 2002.

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Net Income increased $6 million year-to-date but decreased $3 million for the third quarter. The increase for the year was due mainly to higher retail base revenue and wholesale margins, while for the quarter a rise in Operating Expenses offset these increases. Significant fluctuations occurred in Revenues, Fuel and Purchased Electricity due to certain ICR adjustments in 2002 and changing natural gas prices; however, operating income was not significantly affected due to the functioning of the fuel adjustment clause in Oklahoma.

Third Quarter 2003 Compared to Third Quarter 2002

Operating Income

Operating Income decreased $7 million primarily due to the following:

o A $2 million reduction resulting from the absence of the reversal of a Provision for Rate Refund that was recorded in 2002.
o Decreased transmission revenues of $2 million.
o Increased Other Operation and Maintenance expenses of $5 million due in large part to increased tree trimming and postretirement benefits expenses.

The decrease in Operating Income was partially offset by:

o Increased wholesale margins of $3 million due to an increase in our percentage of margins earned from system risk management activities.
o Increased retail base revenue of $5 million due in large part to an increase in industrial revenues. The number of cooling degree-days decreased 2%.

Other Impacts on Earnings

Nonoperating Income increased $6 million primarily due to a gain on the disposition of excess land.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Operating Income

Operating Income increased $6 million primarily due to:

o Increased wholesale margins of $7 million due to an increase in our percentage of margins earned from system risk management activities.
o Increased retail base revenue of $5 million, resulting mainly from increased KWH sales of 3%. Cooling degree-days decreased 5% while heating degree-days increased 14%. . The increase in Operating Income was partially offset by:

o Increased Other Operation expense of $4 million due mainly to employee related expenses consisting largely of increased cost for postretirement benefits.
o Increased Taxes Other Than Income Taxes of $2 million due primarily to increased property value assessments and franchise taxes.

Other Impacts on Earnings

Nonoperating Income increased $5 million primarily due to a gain on the disposition of excess land.

Interest Charges increased $5 million as a result of replacing floating rate short-term debt with longer term fixed rate unsecured debt.

Financial Condition

Credit Ratings

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

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

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from A2 to Baa1 and secured debt from A1 to A3 The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2003 were:

Issuances

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$150	4.85	2010

Retirements

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
First Mortgage Bonds	$ 35	6.25	2003
First Mortgage Bonds	65	7.25	2003

Critical Accounting Policies

See "Registrants' Combined Management's Discussion and Analysis of Financial Condition, Accounting Policies and Other Matters - Critical Accounting Policies" in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Risk management policies and procedures are instituted and administered at the AEP consolidated level for all subsidiary registrants. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about the risk management activities' effect on this specific registrant.

Roll-Forward of MTM Risk Management Contract Net Assets

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

Roll-Forward of MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$3,545
(Gain) Loss from Contracts Realized/Settled During the Period (a)	220
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	-
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of 98-10 Rescission	-
Changes in Fair Value of Risk Management Contracts (d)	-
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	9,564
Total MTM Risk Management Contract Net Assets	13,329
Net Non-Trading Related Derivative Contracts	605
Net Fair Value of Risk Management and Derivative Contracts September 30, 2003	$13,934

(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)"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.
(e)"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.

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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

o 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 September 30, 2003

	Remainder 2003	2004	2005	2006	2007	After 2007	Total
			(in thousands)				
Prices Provided by Other External Sources - OTC Broker Quotes (a)	$287	$3,203	$1,415	$1,241	$294	$-	$6,440
Prices Based on Models and Other Valuation Methods (b)	481	1,164	739	893	985	2,627	6,889
Total	$768	$4,367	$2,154	$2,134	$1,279	$2,627	$13,329

(a) "Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" if there is 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.

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 Other Comprehensive Income (Loss) Activity

Nine Months Ended September 30, 2003

	Domestic Power
	(in thousands)
Accumulated OCI, December 31, 2002	$(42)
Changes in Fair Value (a)	259
Reclassifications from OCI to Net Income (b)	176
Accumulated OCI Derivative Gain (Loss) September 30, 2003	$ 393

(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 OCI 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 Accumulated OCI expected to be reclassified to earnings during the next twelve months is a $685 thousand gain.

Credit Risk

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

VaR Associated with Energy Trading Contracts

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

September 30, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$363	$1,029	$474	$102	$136	$415	$148	$30

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2003	2002	2003	2002
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$355,064	$236,724	$860,544	$535,784
Sales to AEP Affiliates	3,511	(6,626)	17,929	1,630
TOTAL	358,575	230,098	878,473	537,414
OPERATING EXPENSES				
Fuel for Electric Generation	177,162	58,410	415,731	150,279
Purchased Electricity for Resale	11,524	(15,250)	30,878	(7,230)
Purchased Electricity from AEP Affiliates	24,132	38,320	94,515	67,238
Other Operation	33,765	31,957	97,067	92,845
Maintenance	12,763	10,024	34,523	36,079
Depreciation and Amortization	21,715	22,496	64,568	64,473
Taxes Other Than Income Taxes	9,526	9,278	27,611	25,209
Income Taxes	24,461	24,153	28,192	29,200
TOTAL	315,048	179,388	793,085	458,093
OPERATING INCOME	43,527	50,710	85,388	79,321
Nonoperating Income	6,691	1,022	7,413	2,351
Nonoperating Expense	304	2	467	666
Nonoperating Income Tax Expense	1,488	922	1,133	681
Interest Charges	10,336	9,806	34,493	29,351
NET INCOME	38,090	41,002	56,708	50,974
Preferred Stock Dividend Requirements	53	53	159	159
EARNINGS APPLICABLE TO COMMON STOCK	$38,037	$40,949	$56,549	$50,815

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

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF COMMON SHAREHOLDER'S EQUITY AND
COMPREHENSIVE INCOME
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 2002	$157,230	$180,016	$142,994	$-	$480,240
Common Stock Dividends			(67,368)		(67,368)
Preferred Stock Dividends			(159)		(159)
					412,713
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				45	45
NET INCOME			50,974		50,974
TOTAL COMPREHENSIVE INCOME					51,019
SEPTEMBER 30, 2002	$157,230	$180,016	$126,441	$45	$463,732
JANUARY 1, 2003	$157,230	$180,016	$116,474	$(54,473)	$399,247
Capital Contribution from Parent		50,000			50,000
Common Stock Dividends			(15,000)		(15,000)
Preferred Stock Dividends			(159)		(159)
Distribution of Investment in AEMT, Inc. Preferred Shares to Parent			(548)		(548)
TOTAL					433,540
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Minimum Pension Liability				(59)	(59)
Unrealized Gain on Cash Flow Hedges				435	435
NET INCOME			56,708		56,708
TOTAL COMPREHENSIVE INCOME					57,084
SEPTEMBER 30, 2003	$157,230	$230,016	$157,475	$(54,097)	$490,624

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,064,055	$1,040,520
Transmission	447,286	432,846
Distribution	1,012,605	990,947
General	194,317	206,747
Construction Work in Progress	52,881	88,444
TOTAL	2,771,144	2,759,504
Accumulated Depreciation and Amortization	1,253,819	1,239,855
TOTAL - NET	1,517,325	1,519,649
Other Property and Investments	7,147	5,383
Long-term Risk Management Assets	15,967	4,481
CURRENT ASSETS		
Cash and Cash Equivalents	17,587	16,774
Advances to Affiliates	103,453	-
Accounts Receivable:		
Customers	26,639	31,687
Affiliated Companies	25,160	14,139
Allowance for Uncollectible Accounts	(47)	(84)
Fuel Inventory	18,551	19,973
Materials and Supplies	37,444	37,375
Under-recovered Fuel Costs	43,608	76,470
Risk Management Assets	12,772	3,841
Prepayments and Other	3,633	2,735
TOTAL	288,800	202,910
Regulatory Assets	25,838	26,150
Deferred Charges	29,184	18,117
TOTAL ASSETS	$1,884,261	$1,776,690

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - $15 Par Value:		
Authorized Shares: 11,000,000		
Issued Shares: 10,482,000		
Outstanding Shares: 9,013,000	$157,230	$157,230
Paid-in Capital	230,016	180,016
Accumulated Other Comprehensive Income (Loss)	(54,097)	(54,473)
Retained Earnings	157,475	116,474
Total Common Shareholder's Equity	490,624	399,247
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,267	5,267
PSO - Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of PSO	-	75,000
Long-term Debt	672,691	445,437
TOTAL	1,168,582	924,951
Other Noncurrent Liabilities	55,906	54,761
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	-	100,000
Advances from Affiliates	-	86,105
Accounts Payable:		
General	52,350	61,169
Affiliated Companies	96,358	78,076
Customer Deposits	25,172	21,789
Taxes Accrued	19,196	6,854
Interest Accrued	7,648	6,979
Risk Management Liabilities	7,873	3,260
Other	20,484	24,957
TOTAL	229,081	389,189
Deferred Income Taxes	350,295	341,396
Deferred Investment Tax Credits	30,858	32,201
Regulatory Liabilities and Deferred Credits	42,607	32,611
Long-Term Risk Management Liabilities	6,932	1,581
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,884,261	$1,776,690

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$56,708	$50,974
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	64,568	64,473
Deferred Income Taxes	6,536	33,841
Deferred Investment Tax Credits	(1,343)	(1,343)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(6,010)	(27,994)
Fuel, Materials and Supplies	1,353	426
Accounts Payable	9,463	35,739
Taxes Accrued	12,342	11,124
Fuel Recovery	32,862	(108,565)
Deferred Property Taxes	(8,239)	(8,092)
Changes in Other Assets	(6,165)	(103)
Changes in Other Liabilities	54	(31,825)
Net Cash Flows From Operating Activities	162,129	18,655
INVESTING ACTIVITIES		
Construction Expenditures	(59,263)	(51,629)
Proceeds from Sale of Property	2,664	963
Net Cash Flows Used For Investing Activities	(56,599)	(50,666)
FINANCING ACTIVITIES		
Capital Contributions from Parent	50,000	-
Issuance of Long-term Debt	150,000	-
Change in Advances to/from Affiliates, Net	(189,558)	105,551
Retirement of Long-term Debt	(100,000)	-
Dividends Paid on Common Stock	(15,000)	(67,368)
Dividends Paid on Cumulative Preferred Stock	(159)	(159)
Net Cash Flows From (Used For) Financing Activities	(104,717)	38,024
Net Increase in Cash and Cash Equivalents	813	6,013
Cash and Cash Equivalents at Beginning of Period	16,774	5,795
Cash and Cash Equivalents at End of Period	$17,587	$11,808

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $31,572,000 and $24,853,000 and for income taxes was $33,658,000 and $2,962,000 in 2003 and 2002, respectively.

There was a non-cash distribution of $548,000 in preferred shares in AEMT, Inc. to PSO's Parent Company in 2003.

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Net Income for the first nine months of 2003 increased $10 million due to the adoption of SFAS 143, which resulted in a Cumulative Effect of Accounting Changes of $9 million in the first quarter of 2003. Net Income for the third quarter decreased $4 million due to decreased margins and increased Interest Charges. Significant fluctuations occurred in revenues, fuel and purchased power due to certain ICR adjustments in 2002 and changing natural gas prices; however, income is generally not affected due to the functioning of fuel adjustment clauses in the retail jurisdictions.

Third Quarter 2003 Compared to Third Quarter 2002

Operating Income

Operating Income decreased by $1 million primarily due to:

o A $2 million decrease in retail base revenues in large part due to a 9% decline in cooling-degree days.
o A decline in risk management activities of $5 million.
o A 19% increase in fuel expense resulting from a higher per unit cost of fuel, mostly natural gas, offset partially by reduced purchased power expense.
o An increase of $1 million from Taxes Other Than Income Taxes due in large part to increased property taxes resulting from revised tax valuations.
o A $3 million increase in Other Operation expense primarily due to increased deferred fuel expense.

The decrease in Operating Income was partially offset by:

o An increase in retained margins from off-system sales of $6 million due to larger volumes.
o A decrease in Maintenance expense of $1 million due mainly to reduced scheduled power plant maintenance.
o A decrease of $1 million in Income Taxes due to a decrease in pre-tax operating book income.

Other Impacts on Earnings

Interest Charges increased $2 million primarily due to higher overall levels of outstanding debt.

Minority Interest expense of $1 million is a result of consolidating Sabine Mining Company during the third quarter of 2003, due to the implementation of FIN 46. See Notes 2 and 6 for additional discussion.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Operating Income

Operating Income increased by $6 million primarily due to:

o An increase in retained margins from off-system sales of $11 million due to larger volumes.
o An increase in retail base revenues of $6 million due to an increased number of customers and their average usage, offset in part by milder weather. Cooling degree-days declined 8% while heating degree-days increased 2%.
o A $7 million increase in transmission revenues.
o An increase in risk management activities of $4 million.
o A decrease in Other Operation expense of $6 million primarily due to reduced transmission expense of $4 million.
o A $2 million decrease in Maintenance expense due to reduced scheduled power plant maintenance and reduced tree trimming expense.

The increase in Operating Income was partially offset by:

o A $7 million decrease in wholesale base margins partly due to decreased demand from wholesale customers.
o A decrease in capacity revenues of $4 million, due to the elimination of the requirement under the Texas Restructuring legislation to sell capacity since they did not transition to competition.
o An increase in fuel expense of 17% due to a higher per unit cost of fuel, mostly natural gas, offset partially by reduced purchased power expense.

o A $3 million increase in Taxes Other Than Income Taxes due mainly to increased property taxes resulting from revised tax valuations.
o An increase in Income Taxes of $2 million due to an increase in pre-tax operating book income and a change in certain book versus tax differences accounted for on a flow-through basis.

Other Impacts on Earnings

Interest Charges increased $5 million primarily due to higher overall levels of outstanding debt.

Minority Interest expense of $1 million is a result of consolidating Sabine Mining Company during the third quarter of 2003, due to the implementation of FIN 46. See Notes 2 and 6 for additional discussion.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

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

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

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from A2 to Baa1 and secured debt from A1 to A3. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

Cash Flow

Cash flows for the nine months ended September 30, 2003 and 2002 were as follows:

	2003	2002
	(in thousands)	
Cash and cash equivalents at beginning of period	$2,069	$5,415
Cash flows from (used for):		
Operating activities	207,874	195,639
Investing activities	(77,403)	(72,809)
Financing activities	(115,951)	(122,541)
Net increase in cash and cash equivalents	14,520	289
Cash and cash equivalents at end of period	$16,589	$5,704

Operating Activities

Cash flows from operating activities increased $12 million in the first nine months of 2003 compared to the first nine months of 2002 primarily due to a change in under-recovery of fuel costs due to higher natural gas prices in 2003 and a build-up of fuel inventory during 2002.

Investing Activities

Cash spent on investing activities increased $5 million in comparison to the prior year. In 2003, $68 million of construction expenditures were related to projects for improved transmission and distribution service reliability.

Financing Activities

Cash flows used for financing activities in the first nine months of 2003 were comparable to the first nine months of 2002. During the first quarter of 2003 we retired $55 million of first mortgage bonds at maturity. In April 2003, we issued $100 million of senior unsecured debt due 2015 at a coupon of 5.375%. In May 2003, one of our mining subsidiaries issued $44 million of notes due in 2011 at a coupon of 4.47%. The loan will be used primarily to reduce a note to us with an interest rate of 8.06%.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2003 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in millions)	(%)	
Senior Unsecured Notes	$100	5.375	2015
Secured Note of Subsidiary	44	4.47	2011

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in millions)	(%)	
First Mortgage Bonds	$55	6.625	2003
Secured Note of Subsidiary	2	4.47	2011
Notes Payable	1	Variable	2008

Significant Factors

NOx Reductions

The Texas Commission on Environmental Quality adopted rules requiring significant reductions in NOx emissions from utility sources, including SWEPCo. Our compliance date is May 2005. We are installing combustion control technology to reduce NOx emissions on certain units to comply with these rules. Our estimates indicate that compliance with the rules could result in required capital expenditures of approximately $35 million. The actual cost to comply could be significantly different than the estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital or operating costs for additional pollution control equipment are recovered from customers, these costs would adversely affect future results of operations, cash flows and possibly financial condition. See Note 5 for further discussion.

Critical Accounting Policies

See "Registrants' Combined Management's Discussion and Analysis of Financial Condition, Accounting Policies and Other Matters - Critical Accounting Policies" in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Risk management policies and procedures are instituted and administered at the AEP consolidated level for all subsidiary registrants. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about the risk management activities' effect on this specific registrant.

Roll-Forward of MTM Risk Management Contract Net Assets

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

Roll-Forward of MTM Risk Management Contract Net Assets Nine Months Ended September 30, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$4,050
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(354)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	-
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of 98-10 Rescission	151
Changes in Fair Value of Risk Management Contracts (d)	4,161
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	7,690
Total MTM Risk Management Contract Net Assets	15,698
Net Non-Trading Related Derivative Contracts	(531)
Net Fair Value of Risk Management and Derivative Contracts September 30, 2003	$15,167

(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)"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.
(e)"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.

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:
o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 September 30, 2003

	Remainder 2003	2004	2005	2006	2007	After 2007	Total
			(in thousands)				
Prices Provided by Other External Sources - OTC Broker Quotes (a)	$337	$3,773	$1,667	$1,461	$346	$-	$7,584
Prices Based on Models and Other Valuation Methods (b)	567	1,371	870	1,052	1,160	3,094	8,114
Total	$904	$5,144	$2,537	$2,513	$1,506	$3,094	$15,698

(a)"Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b)"Prices Based on Models and Other Valuation Methods" if there is 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.

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 Other Comprehensive Income (Loss) Activity Nine Months Ended September 30, 2003

	Domestic Power
	(in thousands)

Accumulated OCI, December 31, 2002	$(48)
Changes in Fair Value (a)	303
Reclassifications from OCI to Net Income (b)	207
Accumulated OCI Derivative Gain (Loss) September 30, 2003	$462

(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 OCI 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 Accumulated OCI expected to be reclassified to earnings during the next twelve months is a $807 thousand gain.

Credit Risk

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

VaR Associated with Energy Trading Contracts

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

September 30, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$427	$1,212	$558	$121	$155	$474	$170	$34

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2003	2002	2003	2002
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$347,672	$346,519	$835,193	$794,668
Sales to AEP Affiliates	13,950	15,904	63,013	53,088
TOTAL	361,622	362,423	898,206	847,756
OPERATING EXPENSES				
Fuel for Electric Generation	145,201	122,446	358,917	306,536
Purchased Electricity for Resale	6,567	29,820	29,499	40,290
Purchased Electricity from AEP Affiliates	10,055	10,257	35,706	27,817
Other Operation	53,743	51,005	131,256	137,288
Maintenance	15,959	16,767	47,707	49,547
Depreciation and Amortization	30,381	31,764	89,284	92,437
Taxes Other Than Income Taxes	16,517	15,259	45,558	42,205
Income Taxes	23,970	24,851	39,418	36,925
TOTAL	302,393	302,169	777,345	733,045
OPERATING INCOME	59,229	60,254	120,861	114,711
Nonoperating Income	1,364	1,203	2,711	1,618
Nonoperating Expenses	577	344	1,453	1,298
Nonoperating Income Tax Expense (Credit)	18	176	(37)	67
Interest Charges	16,981	15,143	48,058	42,856
Minority Interest	(836)	-	(836)	-
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	42,181	45,794	73,262	72,108
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	8,517	-
NET INCOME	42,181	45,794	81,779	72,108
Preferred Stock Dividend Requirements	57	57	172	172
EARNINGS APPLICABLE TO COMMON STOCK	$42,124	$45,737	$81,607	$71,936

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

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY AND
COMPREHENSIVE INCOME (LOSS)
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 2002	$135,660	$245,003	$308,915	$-	$689,578
Common Stock Dividends			(56,889)		(56,889)
Preferred Stock Dividends			(172)		(172)
TOTAL					632,517
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				50	50
NET INCOME			72,108		72,108
TOTAL COMPREHENSIVE INCOME					72,158
SEPTEMBER 30, 2002	$135,660	$245,003	$323,962	$50	$704,675
JANUARY 1, 2003	$135,660	$245,003	$334,789	$(53,683)	$661,769
Common Stock Dividends			(54,596)		(54,596)
Preferred Stock Dividends			(172)		(172)
					607,001
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				510	510
NET INCOME			81,779		81,779
TOTAL COMPREHENSIVE INCOME					82,289
SEPTEMBER 30, 2003	$135,660	$245,003	$361,800	$(53,173)	$689,290

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,651,234	$1,503,722
Transmission	609,775	575,003
Distribution	1,071,355	1,063,564
General	409,012	378,130
Construction Work in Progress	54,797	75,755
TOTAL	3,796,173	3,596,174
Accumulated Depreciation and Amortization	1,852,603	1,697,338
TOTAL - NET	1,943,570	1,898,836
Other Property and Investments	6,516	5,978
Long-term Risk Management Assets	18,804	5,119
CURRENT ASSETS		
Cash and Cash Equivalents	16,589	2,069
Advances to Affiliates	123,790	-
Accounts Receivable:		
Customers	43,782	62,359
Affiliated Companies	49,204	19,253
Allowance for Uncollectible Accounts	(2,140)	(2,128)
Fuel Inventory	57,499	61,741
Materials and Supplies	34,227	33,539
Under-recovered Fuel Costs	-	2,865
Risk Management Assets	15,041	4,388
Prepayments and Other	19,978	17,851
TOTAL	357,970	201,937
Regulatory Assets	52,715	49,233
Deferred Charges	70,183	47,572
TOTAL ASSETS	$2,449,758	$2,208,675

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2003 and December 31, 2002
(Unaudited)

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - $18 Par Value:		
Authorized - 7,600,000 Shares		
Outstanding - 7,536,640 Shares	$135,660	$135,660
Paid-in Capital	245,003	245,003
Accumulated Other Comprehensive Income (Loss)	(53,173)	(53,683)
Retained Earnings	361,800	334,789
Total Common Shareholder's Equity	689,290	661,769
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,701
SWEPCo - Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of SWEPCo	-	110,000
Long-term Debt	833,055	637,853
TOTAL	1,527,045	1,414,323
Minority Interest	1,651	-
Other Noncurrent Liabilities	111,107	78,494
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	95,424	55,595
Advances from Affiliates, Net	-	23,239
Accounts Payable - General	49,352	62,139
Accounts Payable - Affiliated Companies	56,345	58,773
Customer Deposits	23,659	20,110
Taxes Accrued	62,641	19,081
Interest Accrued	15,308	17,051
Risk Management Liabilities	9,876	

		3,724
Over-recovered Fuel	611	17,226
Other	45,661	34,565
	-----------	-----------
TOTAL	358,877	311,503
	-----------	-----------
Deferred Income Taxes	352,601	341,064
Deferred Investments Tax Credits	40,945	44,190
Regulatory Liabilities and Deferred Credits	48,730	17,295
Long-term Risk Management Liabilities	8,802	1,806
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,449,758	$2,208,675
	===========	===========

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$81,779	$72,108
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	89,284	92,437
Deferred Income Taxes	421	(15,296)
Deferred Investment Tax Credits	(3,245)	(3,393)
Cumulative Effect of Accounting Changes	(8,517)	-
Mark-to-Market of Risk Management Contracts	(11,497)	(4,534)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(8,862)	(10,293)
Fuel, Materials and Supplies	10,095	(6,596)
Accounts Payable	(18,773)	7,280
Taxes Accrued	42,396	56,866
Fuel Recovery	(13,750)	24,660
Deferred Property Taxes	(9,315)	(8,772)
Change in Other Assets	(3,088)	(24,717)
Change in Other Liabilities	60,946	15,889
Net Cash Flows From Operating Activities	207,874	195,639
INVESTING ACTIVITIES		
Construction Expenditures	(86,488)	(73,483)
Proceeds from Sale of Assets and Other	9,085	674
Net Cash Flows Used For Investing Activities	(77,403)	(72,809)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	144,324	198,614
Retirement of Long-term Debt	(58,478)	(150,450)
Change in Advances to/from Affiliates, Net	(147,029)	(113,644)
Dividends Paid on Common Stock	(54,596)	(56,889)
Dividends Paid on Cumulative Preferred Stock	(172)	(172)
Net Cash Flows Used For Financing Activities	(115,951)	(122,541)
Net Increase in Cash and Cash Equivalents	14,520	289
Cash and Cash Equivalents at Beginning of Period	2,069	5,415
Cash and Cash Equivalents at End of Period	$16,589	$5,704

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $45,211,000 and $34,860,000 and for income taxes was $26,166,000 and $24,102,000 in 2003 and 2002, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

NOTES TO RESPECTIVE FINANCIAL STATEMENTS
SEPTEMBER 30, 2003
(Unaudited)

The notes to 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.	General	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements and Cumulative Effect of Accounting Changes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3.	Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
4.	Customer Choice and Industry Restructuring	APCo, CSPCo, I&M, OPCo, SWEPCo, TCC, TNC
5.	Commitments and Contingencies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
6.	Guarantees	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
7.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
8.	Leases	OPCo
9.	Financing and Related Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC

1. GENERAL

The accompanying unaudited interim financial statements should be read in conjunction with the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003) as incorporated in and filed with the Form 10-K.

Certain prior period financial statement items have been reclassified to conform to current period presentation. These items include gains and losses associated with derivative trading contracts presented on a net basis in accordance with EITF 02-3, and counterparty netting in accordance with FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" and EITF Topic D-43, "Assurance That a Right of Setoff is Enforceable in a Bankruptcy under FASB Interpretation No. 39." Such reclassifications had no effect on previously reported Net Income.

In the opinion of management, the unaudited interim financial statements reflect all normal recurring accruals and adjustments which are necessary for a fair presentation of the results of operations for interim periods.

2. NEW ACCOUNTING PRONOUNCEMENTS AND CUMULATIVE EFFECT OF ACCOUNTING **CHANGES**

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, $321 million ($75 million PSO, $110 million SWEPCo and $136 million TCC), previously reported as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries, is now reported as a component of Long-term Debt.

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 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 Funding, LP (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 8 "Leases" for further disclosures.

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 in 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 the first quarter of 2003, AEP recorded an unfavorable cumulative effect for its 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 nine months ended September

30, 2003.

Certain of AEP's registrant subsidiaries have recorded in Accumulated Depreciation and Amortization, removal costs collected 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, in the first quarter 2003 the registrant subsidiaries reversed the balance of such removal costs from accumulated depreciation which resulted in a net favorable cumulative effect in the first quarter of 2003. However, the registrant subsidiaries did not adjust the balance of such removal costs for their regulated operations, and in accordance with the present method of recovery, will continue to record such amounts through depreciation expense and accumulated depreciation.

The following is a summary by registrant subsidiary of the regulatory liabilities for removal costs included in Accumulated Depreciation and Amortization:

	September 30, 2003	December 31, 2002
	(in millions)	
AEGCo	$ 28.6	$ 28.0
APCo	90.0	94.6
CSPCo	98.0	96.0
I&M	260.9	250.5
KPCo	22.0	23.7
OPCo	97.6	97.0
PSO	203.7	202.6
SWEPCo	229.5	219.5
TCC	101.7	97.5
TNC	76.4	75.0

The following is a summary by registrant subsidiary of the cumulative effect of changes in accounting principles, as a result of SFAS 143, for the nine months ended September 30, 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 September 30, 2003
		(in millions)		
AEGCo (a)	$1.1	$-	$-	$1.1
APCo (a)	20.1	1.2	-	21.3
CSPCo (a)	8.1	0.5	-	8.6
I&M (b)	516.1	27.6	-	543.7
OPCo (a)	39.5	2.3	-	41.8
SWEPCo (d)	-	0.2	8.1	8.3
TCC (c)	203.2	11.6	-	214.8

(a) Consists of asset retirement obligations related to ash ponds.
(b) Consists of asset retirement obligations related to ash ponds ($1.1 million at September 30, 2003) and nuclear decommissioning costs for the Cook Plant ($542.6 million at September 30, 2003).
(c) Consists of asset retirement obligations related to nuclear decommissioning costs for STP.
(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" above).

Accretion expense is included in Other Operation expense in the respective Income Statements of the individual subsidiary registrants.

As of September 30, 2003 and December 31, 2002, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $800 million ($685 million for I&M and $115 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 Nuclear Decommissioning Trust Fund on TCC's Consolidated Balance Sheets.

Pro forma net income has not been presented for the quarter ended September 30, 2002 or the years ended December 31, 2002, 2001 and 2000 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	December 31, 2001
	(in millions)	
AEGCo	$ 1.1	$ 1.0
APCo	20.1	18.7
CSPCo	8.1	7.5
I&M	516.1	481.4
KPCo	-	-
OPCo	39.5	36.5
PSO	-	-
SWEPCo	-	-
TCC	203.2	188.8
TNC	-	-

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 energy trading 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 energy trading transactions occurring on or after October 25, 2002. For physical inventory and non-derivative energy trading 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.

The following is a summary by registrant subsidiary of the cumulative effect of changes in accounting principles recorded in the first quarter of 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	-	-

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, 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 result of 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.

SFAS 150 requires that the following three types of freestanding financial instruments be reported as liabilities: (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) obligations that can be settled with shares, the monetary value of which is either (a) fixed, (b) tied to the value of a variable other than the issuer's shares, or (c) varies inversely with the value of the issuer's 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. Upon adoption of SFAS 150, any measurement change for these liabilities is to be reported as the cumulative effect of a change in accounting principle.

Beginning with the third quarter 2003 financial statements, $83 million ($11 million APCo, $63 million I&M and $9 million OPCo) of Cumulative Preferred Stock Subject to Mandatory Redemption is now presented as Liability for Cumulative Preferred Stock Subject to Mandatory Redemption within the Capitalization section of the balance sheet in order to identify it as a liability. Beginning July 1, 2003, dividends on these mandatorily redeemable preferred shares are now classified as Interest Charges on the statements of operations. 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. This guidance is an interpretation of SFAS 5, 57 and 107 and a rescission of FIN 34. The initial recognition and initial measurement provisions of FIN 45 are effective on a prospective basis for guarantees issued or modified after December 31, 2002. The disclosure requirements of FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002. See Note 6 for further disclosures.

Future Accounting Changes

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.

3. RATE MATTERS

Fuel in SPP Area of Texas - Affecting SWEPCo and TNC

As discussed in Note 6 of the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), 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 area before January 1, 2007. The PUCT has ruled that TNC fuel factors in the SPP area will be based upon the PTB fuel factors offered by the REP in the ERCOT portion of TNC's service territory. 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 its SPP area. The adjustments removed $3.71 per MWH from reconcilable fuel expense. This adjustment will reduce revenues received from TNC's SPP customers by approximately $400,000 annually. These customers are now served by SWEPCo's REP.

TNC Fuel Reconciliation - Affecting TNC

In June 2002, TNC filed with the PUCT to reconcile fuel costs and 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 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. The under-recovery balance at December 31, 2001 for TNC's service within SPP was $0.7 million including interest. As noted above, TNC's SPP customers are now being served by SWEPCo's REP.

In March 2003, the Administrative Law Judges (ALJ) in this proceeding filed their Proposal for Decision (PFD). The PFD includes a recommendation that TNC's under-recovered retail fuel balance be reduced by approximately $12.5 million. In March 2003, TNC established a reserve of $13 million, including interest, based on the recommendations in the PFD. On April 22, 2003, TNC and intervenors in this proceeding filed exceptions to the PFD. On May 28, 2003, the PUCT remanded TNC's final fuel reconciliation to the ALJ to consider two issues. These remand issues could result in additional disallowances. The issues are the sharing of off-system sales margins from AEP's trading activities with customers through the fuel factor 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 is proposing that the sharing of off-system sales margins should continue beyond the termination of the fuel factor. 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. TNC made a filing on July 15, 2003 addressing the remand issues. Intervenors and the PUCT Staff filed statements of position or testimony in August 2003 and TNC filed rebuttal testimony in September 2003. The intervenors recommended $14.3 million of disallowances for the two remanded issues. On September 9, 2003, portions of TNC's testimony which related to the requirements of the AEP/CSW merger settlement to share off-system sales margins were stricken by the ALJ. The ALJ ruled that the requirement to share off-system sales margins had been determined by the PUCT and that the scope of the remand was only to determine the off-system sales margin sharing methodology. 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 and that after a thorough review of the evidence it is only reasonably possible that TNC will ultimately share margins after the end of the Texas fuel factor. Due to a provision established in the first quarter of 2003, the resolution of the fuel factor issue should have an immaterial impact on future results of operations, cash flows and financial condition. However, the ultimate decision could result in additional income reductions for these issues. It is presently expected that the ALJ's PFD and the PUCT's final decision regarding these remanded issues will occur in late 2003 or early 2004.

In February 2002, TNC received a final order from the PUCT in a 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 with the PUCT to reconcile fuel costs and to defer its over-recovery of fuel for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 1998 through December 2001 will be TCC's final fuel reconciliation. 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. Recommendations from intervening parties were received in April 2003 and hearings were held in May 2003. Intervening parties have recommended disallowances totaling $170 million. An ALJ report is expected in 2003 or the first quarter of 2004.

In March 2003, the ALJ hearing the TNC final fuel reconciliation, discussed above, issued a PFD in the TNC proceeding. Various issues addressed in TNC's proceeding may also be applicable to TCC's proceeding. Consequently, TCC established a reserve for potential adverse rulings of $27 million during the first quarter of 2003. Based upon the PUCT's remand of certain TNC issues, TCC established an additional reserve of $9 million in the second quarter of 2003. In July 2003, the ALJ requested that additional information be provided in the TCC fuel reconciliation related to the impact of the TNC remand order on TCC. Management believes, based on advice of counsel, that it is only reasonably possible that it will ultimately be determined that TCC should share off-system sales margins after the end of the Texas fuel factor. However, an adverse ruling 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 4 "Customer Choice and Industry Restructuring."

SWEPCo Texas Fuel Reconciliation - Affecting SWEPCo

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs. This reconciliation covers the period of January 2000 through December 2002. At December 31, 2002, SWEPCo's filing detailed a $2.2 million over-recovery balance including interest. During the reconciliation period, SWEPCo incurred $434.8 million of eligible fuel expense. Any ruling by the PUCT preventing recovery of SWEPCo's fuel costs could have a material impact on future results of operations, cash flows and financial condition. Intervenor and PUCT Staff recommendations will be filed in November 2003 and hearings are scheduled for January 2004.

ERCOT Price-to-Beat Fuel Factor Appeal - Affecting TCC and TNC

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 Court remanded the cases to the PUCT for further proceedings consistent with its ruling. 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. Management appealed the District Court decisions to the Third Court of Appeals and 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

TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from an UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. The UCOS proceeding set the regulated wires rates to be effective when retail electric competition began. Regulated delivery charges include the retail transmission and distribution charge including a nuclear decommissioning fund charge and 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 the AEP REP (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 reducing the PTB rates for the period prior to the sale is approximately $11 million pre-tax. Management has appealed this decision and, based on advice of counsel, believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal, it could have an adverse effect on future results of operations and cash flows.

McAllen Rate Review - 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 has a minimum of 120 days to provide support for its rates to the municipalities. TCC has the right to appeal any rate change by the municipalities to the PUCT. Pursuant to an agreement with the cities, TCC filed the requested support for its rates (test year ending June 30, 2003) with both the cities and the PUCT on November 3, 2003. TCC filed to decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%. 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. A procedural schedule has been developed requiring LPSC Staff and intervenor testimony be filed in January 2004. Management believes that SWEPCo's fuel costs prior to 1999 were proper and have been approved by the LPSC and that SWEPCo's historical fuel costs are reasonable. 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.

FERC Wholesale Fuel Complaints - Affecting TNC

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), 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 have resulted in new contracts. Consequently, an offer of settlement was filed at FERC in June 2003 regarding the fuel complaint and new contracts. Management is unable to predict whether FERC will approve this offer of settlement, but it is not expected to have a significant impact on TNC's financial condition. In March 2002, TNC recorded a provision for refund of $2.2 million before income taxes. TNC anticipates that the provision for refund will be adequate to cover the financial implications resulting from these new contracts. Should FERC fail to approve the settlement and new contracts, the actual refund and final resolution of this matter could differ materially from the provision and may have a negative impact on future results of operations, cash flows and financial condition.

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 Big Sandy Plant. See NOx Reductions in Note 5.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million was effective in May 2003 and an additional $16.2 million was 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 before August 1, 2003 (revised to October 31, 2003). In October 2003, PSO filed the required data for this case and requested an increase of $36 million annually, which is an 8.7% increase over existing base rates. A procedural schedule has not been set for this case. 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

As discussed in Note 6 of the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), PSO had a $44 million under-recovery of fuel costs resulting from a reallocation in 2002 of purchased power costs for periods prior to January 1, 2002. On July 23, 2003, PSO filed with the OCC seeking recovery of the $44 million over an eighteen-month time period. In August 2003, the OCC Staff filed testimony recommending recovery of $42.4 million ($44 million less two audit adjustments) over three years. In September 2003, the OCC expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. If the OCC does not permit recovery of the $42.4 million or determines, as a result of the review, that material fuel and purchased power cost 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 would be effective for 17 months and is estimated to reduce revenues by $36 million during that 17-month period. By order dated July 23, 2003, the Virginia SCC approved APCo's requested fuel factor reduction on an interim basis, subject to further investigation. No other parties to the proceeding have raised any issues with respect to APCo's request and the Virginia SCC Staff has filed testimony recommending that APCo's request be approved. 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. A hearing on this matter was held on November 5, 2003.

FERC Long-term Contracts - Affecting AEP East and AEP West companies

In September 2002, the FERC voted to hold hearings to consider requests from certain wholesale customers located in Nevada and Washington to break long-term contracts which they allege are "high-priced." At issue are long-term contracts entered into during the California energy price spike in 2000 and 2001. The complaints allege that AEP sold power at unjust and unreasonable prices. The FERC delayed hearings to allow the parties to hold settlement discussions. In January 2003, the FERC settlement judge indicated that the parties' settlement efforts were not progressing and he recommended that the complaint be placed back on the schedule for a hearing. 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 a similar complaint, a FERC administrative law judge (ALJ) ruled in favor of AEP and dismissed, in December 2002, a complaint filed by two Nevada utilities. In 2000 and 2001, AEP agreed to sell power to the utilities for future delivery. In late 2001, the utilities filed complaints 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 consummated. 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. At a hearing held in April 2003, the utilities asked FERC to void the long-term contracts. In June 2003, the FERC issued an order affirming the ALJ's decision and denying the utilities' complaint. The utilities requested a rehearing. In August 2003, the FERC granted the request for rehearing. Management is unable to predict the outcome of this proceeding or 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 $24 million of RTO formation and integration costs and related carrying charges (APCo-$7 million, CSPCo-$3 million, I&M-$5 million, KPCo-$1 million, OPCo-$8 million) through September 30, 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 the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO until after June 30, 2004 and only then with the approval of the Virginia SCC. 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 allowing us to submit additional evidence. A hearing date has not been scheduled.

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 ($2 million for I&M) before any deferral of the costs for future recovery. On September 30, 2003, AEP filed a petition for reconsideration of the IURC's order, asking the IURC to clarify that its discussion of the Alliance formation costs was not intended to cause an immediate write-off of the Indiana retail portion of these costs.

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 rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo. APCo's base rates are capped with no changes possible prior to January 1, 2004. AEP intends 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 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 $23 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.

FERC Order on Regional Through and Out Rates - Affecting APCo, CSPCo, I&M, KPCo and OPCo

On July 23, 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 Regional Through and Out Rates (RTOR) on transactions where the energy is delivered within the Midwest ISO and PJM regions (RTO Footprint). In October 2003, the FERC postponed the November 1, 2003 deadline to eliminate RTOR. The elimination of the RTORs 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 RTORs. The FERC also found that the RTOR of some of the former Alliance RTO Companies, including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the Midwest ISO/PJM regions. FERC has initiated an investigation and hearing in regard to these rates. AEP made a filing with the FERC supporting the justness and reasonableness of its rates in August 2003 and made a joint filing with unaffiliated utilities, on October 14, 2003, proposing a regional revenue replacement mechanism for the lost revenues, in the event that FERC eliminates AEP's ability to collect RTOR in the RTO Footprint. Also on October 14, 2003, FERC issued an order delaying the November 1, 2003 elimination of RTORs without setting a new date for such elimination. The AEP East companies received approximately $150 million of RTOR 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 the ultimate outcome of this investigation, or its impact on 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. 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. For the 2004 plan year, I&M was required to file a PSCR Plan case with the MPSC by September 30, 2003. 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.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

As discussed in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 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 in 2003 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 other applicable law by failing to participate in an RTO.

The complainants seek, among other relief, an order from the PUCO:
o suspending collection of transition charges by CSPCo and OPCo until transfer occurred
o 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
o 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 the FERC's reversal of its previous approval of our RTO filings and 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 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, or the outcome of these proceedings before the PUCO.

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.

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. The PUCO has circulated a draft of proposed rules but has not yet identified the method by which it will determine market rates for Default Service following the MDP.

As provided in stipulation agreements approved by the PUCO, CSPCo and OPCo are deferring customer choice implementation 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. At September 30, 2003, CSPCo has incurred $31 million and deferred $11 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 next Ohio filing for new distribution rates. Approved rates will not become effective prior to 2009 for CSPCo and 2008 for OPCo. 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

On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in other areas of Texas including the SPP area in which SWEPCo operates. In May 2003, the PUCT approved a stipulation that delays competition in the SPP area until at least January 1, 2007.

A 2004 true-up proceeding will determine the amount and recovery of stranded plant costs as of December 31, 2001 including certain environmental costs incurred by May 1, 2003, final deferred fuel balance, net generation-related regulatory assets, unrefunded accumulated excess earnings, excess of price-to-beat revenues over market prices subject to certain conditions and limitations (Retail clawback), a true-up of the power costs used in the PUCT's ECOM model for 2002 and 2003 to reflect actual market prices determined through legislatively-mandated capacity auctions (wholesale capacity auction true-up) and other restructuring true-up issues.

The Texas Legislation provides for an earnings test each year from 1999 through 2001 and requires PUCT approval of the annual earnings test calculation. TCC, TNC and SWEPCo had appealed the PUCT's Final 2000 Earnings Test Order to the Texas Court of Appeals. In August 2003, the Appeals Court reversed the PUCT order and the district court judgment affirming it and remanded the controversy back to the PUCT for proceedings consistent with the Appeals Court's decision. The PUCT requested rehearing of the Court of Appeal's decision. Our 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 Final Orders, the companies reversed a portion of their regulatory liability and credited amortization expense during the third quarter of 2003. Pre-tax amounts by company were $5.1 million for TCC, $2.6 million for TNC and $1.1 million for SWEPCo.

The Texas Legislation provides for the affiliated PTB REP to refund to its transmission and distribution (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. The retail clawback regulatory liability is to be included in the 2004 true-up proceedings and netted against other true-up adjustments. If 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. In July 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. On August 21, 2003, the PUCT dismissed these filings and ruled that TCC and TNC should refile no sooner than September 22, 2003 in order to establish the required notice period. TCC and TNC refiled in late September 2003. In October 2003, the PUCT Staff recommended approval of TCC's application and denial of TNC's application. The PUCT Staff determined that only 39.9% of TNC's small commercial customers were served by competitive REPs as of the end of August 2003. If the PUCT denies TNC's application, TNC will likely meet the 40% threshold in September 2003 and refile its application. AEP had accrued a regulatory liability of approximately $9 million for the small commercial retail clawback on its REP's books. If the PUCT certifies that TCC and/or TNC have reached the 40% threshold, the regulatory liability would no longer be required for the small commercial class and could be reversed.

The Texas Legislation allows for several alternative methods to be used to value stranded generation assets in the 2004 true-up proceeding including the sale or exchange of generation assets, stock valuation methods or the use of an ECOM model for nuclear generation assets. TCC is the only AEP subsidiary that has stranded costs under the Texas Legislation.

In the fourth quarter of 2002, TCC decided to determine the market value of its generating assets through the sale of those assets for purposes of determining stranded costs for the 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. 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. The filing included a request for the PUCT to issue a declaratory order that TCC's 25.2% ownership interest in its nuclear plant, STP, can be sold to establish its market value for determining stranded plant costs. Intervenors to this proceeding, including the PUCT Staff, made filings to dismiss TCC's filing claiming that the PUCT does not have the authority to issue such a declaratory order. The intervenors also argued that the proper time to address the sales process is after the plants are sold during the 2004 true-up proceeding. Since the closing process for the plants sold is not expected to be completed before mid-2004, TCC requested that its 2004 true-up proceeding be scheduled after completion of the divestiture of its generating assets.

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. The PUCT dismissed TCC's request to certify its proposed divestiture plan; therefore its divestiture plan will be subject to a review in the 2004 true-up proceeding. The PUCT adopted a rule 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.

Texas Legislation also requires that electric utilities and their affiliated power generation companies (PGC) sell at auction in 2002 and 2003 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 replace the PUCT's earlier estimates of those market prices for 2002 and 2003 used in the ECOM model to calculate the wholesale capacity auction true-up adjustment for TCC for the 2004 true-up proceeding.

The decision to determine stranded costs by selling TCC's generating plants and the expectation that the sales price would produce a significant loss/stranded cost instead of using the PUCT's ECOM model negative stranded cost estimate, enabled TCC to record in 2002 a $262 million regulatory asset and related revenues which represents the quantifiable amount of the wholesale capacity auction true-up for the year 2002. Through September 30, 2003, TCC recorded an additional $169 million regulatory asset and related revenues for wholesale capacity auction true-up. Prior to the decision to pursue a sale of TCC's generating assets, the PUCT's negative ECOM estimate prohibited the recognition of the regulatory assets and revenues, as they can not be recovered unless there are 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 plant costs.

In July 2003, the PUCT Staff published their proposed filing package for the 2004 true-up proceeding. Within the filing package are instructions and sample schedules that demonstrate the calculation of the wholesale capacity auction true-up. That calculation differs from the methodology being employed by TCC. TCC filed comments on the proposed 2004 true-up filing package in September 2003 and took exception to the methodology employed by the PUCT Staff. A true-up filing package will probably be approved by the PUCT in the fourth quarter of 2003. If the PUCT Staff's methodology is approved, TCC's wholesale capacity auction true-up regulatory asset could require adjustment.

In October 2003, a coalition of consumer groups (the Coalition of Ratepayers) including the Office of Public Utility Counsel, the State of Texas, Cities served by CPL and Texas Industrial Energy Consumers filed a petition with the PUCT requesting that the PUCT initiate a rulemaking to amend the PUCT's stranded cost true-up rule (True-up Rule). The Coalition of Ratepayers proposed to amend the True-up Rule to revise the calculation of the wholesale capacity auction true-up. If adopted, the Coalition of Ratepayers' proposal would substantially reduce or possibly eliminate the wholesale capacity auction true-up regulatory asset that TCC has accrued in 2002 and 2003. The PUCT requested that responses to the Coalition of Ratepayers' petition be filed by November 7, 2003. On November 5, 2003, the PUCT denied the Coalition of Ratepayers' petition.

When the plant divestitures and the 2004 true-up proceeding are completed, TCC will file to recover PUCT-approved stranded costs and other true-up amounts that are in excess of current securitized amounts plus a carrying charge through a non-bypassable competition transition charge in rates of the regulated T&D utility. In addition, TCC may seek to securitize certain of the approved stranded plant costs and regulatory assets, 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 TCC and TNC are unable, after the 2004 true-up proceeding, to recover all or a portion of their generation-related regulatory assets, unrecovered fuel balances, stranded plant costs, 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.

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.

5. COMMITMENTS AND CONTINGENCIES

Nuclear Plant Outages - Affecting I&M and TCC

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. 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 I&M's 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.

Federal EPA Complaint and Notice of Violation - Affecting APCo, CSPCo, I&M, and OPCo

As discussed in Note 9 of the Combined Notes to Financial Statements in the 2002 Annual Report (as updated by the Current Report on Form 8-K dated May 14, 2003), AEPSC, APCo, CSPCo, I&M, and OPCo are involved in litigation regarding generating plant emissions under the Clean Air Act. The Federal EPA and a number of states alleged APCo, CSPCo, I&M, OPCo and eleven unaffiliated utilities modified certain units at coal-fired generating plants in violation of the Clean Air Act. The Federal EPA filed complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20-year period.

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 April 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.

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.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the Clear Air Act proceedings and is 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. In the event that 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.

NOx Reductions - Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, SWEPCo and TCC

The Federal EPA issued a NOx Rule requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. The NOx Rule has been upheld on appeal. The compliance date for the NOx Rule is May 31, 2004.

In 2000, the Federal EPA also adopted a revised rule (the Section 126 Rule) granting petitions filed by certain northeastern states under the Clean Air Act. The rule imposes emissions reduction requirements comparable to the NOx Rule beginning May 1, 2003, for most of our coal-fired generating units. Affected utilities, including certain AEP operating companies, petitioned the D.C. Circuit Court to review the
Section 126 Rule.

After review, the D.C. Circuit Court instructed the Federal EPA to justify the methods it used to allocate allowances and project growth for both the NOx Rule and the Section 126 Rule. AEP subsidiaries and other utilities requested that the D.C. Circuit Court vacate the Section 126 Rule or suspend its May 2003 compliance date. In 2001, the D.C. Circuit Court issued an order tolling the compliance

schedule until the Federal EPA responds to the Court's remand. On April 30, 2002, the Federal EPA announced that May 31, 2004 is the compliance date for the
Section 126 Rule. The Federal EPA published a notice in the Federal Register on May 1, 2002 advising that no changes in the growth factors used to set the NOx budgets were warranted. In June 2002, AEP subsidiaries joined other utilities and industrial organizations in seeking a review of the Federal EPA's actions in the D.C. Circuit Court. This action is pending.

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 reduce NOx emissions to comply with the applicable state and Federal NOx requirements. This includes selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units. During 2001, 2002 and 2003, SCR technology commenced operations on units of Gavin, Amos, Mountaineer, Big Sandy and Cardinal plants. Construction of SCR technology at certain other AEP generating units continues. Other combustion control technologies have been installed and commenced operation on a number of units across the AEP System and additional units will be equipped with these technologies.

Our NOx compliance plan is a dynamic plan that is continually reviewed and revised as new information becomes available on the performance of installed technologies and the cost of planned technologies. Certain compliance steps may or may not be necessary as a result of this new information. Consequently, the plan has a range of possible outcomes. Current estimates indicate that AEP's compliance with the NOx Rule, the Texas Commission on Environmental Quality rule and the Section 126 Rule could result in required capital expenditures in the range of $1.3 billion to $1.7 billion, of which $1 billion has been spent through September 30, 2003. Estimated compliance cost ranges and amounts spent by subsidiaries are as follows:

	Estimated Compliance Costs	Amount Spent
	(in millions)	
AEGCo	$28	$7
APCo	464	283
CSPCo	87	68
I&M	39	12
KPCo	180	179
OPCo	531-860	431
SWEPCo	35	23
TCC	5	5

Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than these estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs for additional pollution control equipment are recovered from customers, these costs would adversely affect future results of operations, cash flows and possibly financial condition.

Texas Commercial Energy, LLP Lawsuit - Affecting TCC and TNC

Texas Commercial Energy, LLP (TCE), a Texas REP, has filed a lawsuit in federal District Court in Corpus Christi, Texas 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. This case is in the initial pleading stage. We have filed a Motion to Dismiss. The Court has set a hearing on the Motion to Dismiss for January 2004. Management believes that the claims against AEP and its subsidiaries are without merit. We intend to vigorously defend against the claims.

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. Until the rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Proposed Security Standards - Affecting AEP System

As part of the SMD proposed rulemaking, in July 2002, FERC published for comment proposed security standards. These standards were intended to ensure that all market participants would have a basic security program that would effectively protect the electric grid and related market activities. As proposed, these standards would apply to AEP's power transmission systems, distribution systems and related areas of business. The proposed standards have not been adopted. Subsequently, in 2002, the North American Electric Reliability Council (NERC), with FERC's support, developed a new set of standards to address industry compliance. These new standards closely parallel the initial, proposed FERC standards in both content and compliance time frames, and were approved by the NERC ballot body in June 2003. We have developed financial requirements for security implementation and compliance with these NERC standards, the costs of which are not expected to be material to our future results of operations and cash flows.

6. GUARANTEES

There are no liabilities recorded for guarantees entered into prior to December 31, 2002 by AEP's registrant subsidiaries in accordance with FIN 45. There are certain liabilities recorded for guarantees entered into subsequent to December 31, 2002. These liabilities are immaterial. 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 AEP subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity trading contracts, construction contracts, insurance programs, security deposits, debt service reserves, drilling funds and credit enhancements for issued bonds. All of these LOCs were issued by an AEP subsidiary in the subsidiaries' ordinary course of business. At September 30, 2003, the maximum future payments of all the LOCs are approximately $181 million with maturities ranging from September 30, 2003 to January 2011. Included in these amounts is TCC's LOC for credit enhancement of approximately $40.9 million with a maturity date of November 2003. As the parent of all these subsidiaries, 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 a revolving credit agreement, 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 $60 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 September 30, 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 ($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 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

AEP subsidiaries enter 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, exposure generally does not exceed the sale price. The 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 the first nine months of 2003, AEP's 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 the first nine months of 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

AEP and its 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 September 30, 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 8 "Leases" for disclosure of lease residual value guarantees.

7. 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.

8. LEASES

OPCo has entered into an agreement with JMG Funding LLP (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. The lease is accounted for as an operating lease. Payments under the operating lease 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.

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.

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. 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. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.

9. FINANCING AND RELATED ACTIVITIES

Long-term debt and other securities issuances and retirements during the first nine months of 2003 were:

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Issuances:				
APCo	Senior Unsecured Notes	$200	3.60	2008
APCo	Senior Unsecured Notes	200	5.95	2033
APCo	Installment Purchase Contracts	100	5.50	2022
CSPCo	Senior Unsecured Notes	250	5.50	2013
CSPCo	Senior Unsecured Notes	250	6.60	2033
KPCo	Senior Unsecured Notes	75	5.625	2032
OPCo	Senior Unsecured Notes	250	5.50	2013
OPCo	Senior Unsecured Notes	250	6.60	2033
OPCo	Senior Unsecured Notes	225	4.85	2014
OPCo	Senior Unsecured Notes	225	6.375	2033
PSO	Senior Unsecured Notes	150	4.85	2010
SWEPCo	Senior Unsecured Notes	100	5.375	2015
SWEPCo	Secured Note of Subsidiary	44	4.47	2011
TCC	Senior Unsecured Notes	150	3.00	2005
TCC	Senior Unsecured Notes	100	Variable	2005
TCC	Senior Unsecured Notes	275	5.50	2013
TCC	Senior Unsecured Notes	275	6.65	2033
TNC	Senior Unsecured Notes	225	5.50	2013

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Retirements:				
APCo	First Mortgage Bonds	$ 70	8.50	2022
APCo	First Mortgage Bonds	30	7.80	2023
APCo	First Mortgage Bonds	20	7.15	2023
APCo	Installment Purchase Contracts	10	7.875	2013
APCo	Installment Purchase Contracts	40	6.85	2022
APCo	Installment Purchase Contracts	50	6.60	2022
APCo	Senior Unsecured Notes	100	7.20	2038
APCo	Senior Unsecured Notes	100	7.30	2038
APCo	Senior Unsecured Notes	125	Variable	2003
CSPCo	First Mortgage Bonds	2	8.70	2022
CSPCo	First Mortgage Bonds	15	8.55	2022
CSPCo	First Mortgage Bonds	14	8.40	2022
CSPCo	First Mortgage Bonds	13	8.40	2022
CSPCo	First Mortgage Bonds	13	6.80	2003
CSPCo	First Mortgage Bonds	26	6.55	2004
CSPCo	First Mortgage Bonds	26	6.75	2004
CSPCo	First Mortgage Bonds	40	7.90	2023
CSPCo	First Mortgage Bonds	33	7.75	2023
CSPCo	First Mortgage Bonds	25	6.60	2003
I&M	First Mortgage Bonds	75	8.50	2022
I&M	First Mortgage Bonds	15	7.35	2023

I&M	Junior Debentures	40	8.00	2026
I&M	Junior Debentures	125	7.60	2038
KPCo	Junior Debentures	40	8.72	2025
OPCo	First Mortgage Bonds	30	6.75	2003
PSO	First Mortgage Bonds	35	6.25	2003
PSO	First Mortgage Bonds	65	7.25	2003
SWEPCo	First Mortgage Bonds	55	6.625	2003
SWEPCo	Secured Note of Subsidiary	2	4.47	2011
SWEPCo	Notes Payable	1	Variable	2008
TCC	First Mortgage Bonds	18	7.50	2023
TCC	First Mortgage Bonds	16	6.875	2003
TCC	Securitization Bonds	51	3.54	2005

In addition to the transactions reported in the table above, the following table lists intercompany retirements of debt due to AEP:

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	
Retirements:				
CSPCo	Notes Payable	$160	6.501	2006
KPCo	Notes Payable	15	4.336	2003
OPCo	Notes Payable	240	6.501	2006
OPCo	Notes Payable	60	4.336	2003

LINES OF CREDIT AND RELATED SHORT-TERM BORROWINGS

The AEP System Corporate Borrowing Program is the funding mechanism AEP uses to meet the short-term cash requirements of the system. The Corporate Borrowing Program consists of two primary funding groups: the AEP system Utility Money Pool, used by regulated companies, and the AEP system Non-Utility Money Pool, used by non-regulated companies. The AEP system Corporate Borrowing Program operates consistent 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 September 30, 2003:

	Authorized
	(in millions)
AEP Generating	$125
AEP Texas Central (a)	600
AEP Texas North (a)	275
Appalachian Power	600
Columbus Southern Power (a)	300
Indiana Michigan Power	500
Kentucky Power	200
Ohio Power (a)	250
Public Service Company of Oklahoma	300
Southwestern Electric Power	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, 2003, which authorized financing transactions through March 31, 2006.

CONTROLS AND PROCEDURES

During the third quarter of 2003, AEP's management, including the principal executive officer and principal financial officer, evaluated AEP'sdisclosure controls and procedures related to the recording, processing, summarization and reporting of information in AEP's periodic reports that it files with the SEC. These disclosure controls and procedures have been designed to ensure that (a) material information relating to AEP, including its consolidated subsidiaries, is made known to AEP's management, including these officers, by other employees of AEP and its subsidiaries, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. AEP's controls and procedures can only provide reasonable, not absolute, assurance that the above objectives have been met.

As of September 30, 2003, these officers concluded that the disclosure controls and procedures in place provide reasonable assurance that the disclosure controls and procedures can accomplish their objectives. AEP continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant.

There have not been any changes in AEP's internal controls over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of 2003 that have materially affected, or are reasonably likely to materially affect, AEP's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

For a discussion of material legal proceedings, see Note 6 to AEP's consolidated financial statements and Note 5 to AEP's registrant subsidiaries' respective financial statements, both entitled Commitments and Contingencies, incorporated herein by reference.

Item 5. Other Information.

NONE

Item 6. Exhibits and Reports on Form 8-K.

(a) Exhibits:

AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

Exhibit 12 - Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

Exhibit 31.1 - Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 31.2 - Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 32.1 - Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

Exhibit 32.2 - Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

(b) Reports on Form 8-K:

AEGCo, APCo, I&M, KPCo, PSO, SWEPCo, TCC and TNC

The following reports on Form 8-K were filed during the quarter ended September 30, 2003.

Company Reporting	Date of Report	Item Reported
AEP	July 30, 2003	Item 7. Financial Statements And Exhibits Item 9. Regulation FD Disclosure
OPCo	July 8, 2003	Item 5. Other Events and Regulation FD Disclosure Item 7. Financial Statements And Exhibits
PSO	September 10, 2003	Item 5. Other Events and Regulation FD Disclosure Item 7. Financial Statements And Exhibits

Signature

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

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto

Joseph M. Buonaiuto
Controller and
Chief Accounting
Officer

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

By: /s/Joseph M. Buonaiuto

Joseph M. Buonaiuto
Controller and
Chief Accounting
Officer

Date: November 12, 2003

KENTUCKY POWER COMPANY
Computation of Ratios of Earnings to Fixed Charges
(in thousands except ratio data)

	Year Ended December 31,					Twelve Months Ended
	1998	1999	2000	2001	2002	9/30/03
Fixed Charges:						
Interest on First Mortgage Bonds	$13,936	$12,712	$9,503	$6,178	$2,206	$ --
Interest on Other Long-term Debt	12,188	13,525	16,367	18,300	23,429	26,508
Interest on Short-term Debt	2,455	2,552	3,295	2,329	1,751	1,364
Miscellaneous Interest Charges	634	869	2,523	1,059	1,084	1,751
Estimated Interest Element in Lease Rentals	1,500	1,200	1,700	1,200	1,000	1,000
Total Fixed Charges	$30,713	$30,858	$33,388	$29,066	$29,470	$30,623
Earnings:						
Net Income Before Cumulative Effect of Accounting Change	$21,676	$25,430	$20,763	$21,565	$20,567	$20,698
Plus Federal Income Taxes	9,785	12,993	17,884	9,553	9,235	7,961
Plus State Income Taxes	2,096	2,784	2,457	489	1,627	1,678
Plus Fixed Charges (as above)	30,713	30,858	33,388	29,066	29,470	30,623
Total Earnings	$64,270	$72,065	$74,492	$60,673	$60,899	$60,960
Ratio of Earnings to Fixed Charges	2.09	2.33	2.23	2.08	2.06	1.99

EXHIBIT 31.1
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, E. Linn Draper, Jr., certify that:
1. I have reviewed this quarterly report on Form 10-Q of:

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;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) for the registrant and we have:

designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this quarterly report based on such evaluation; and

disclosed in this quarterly report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 12, 2003

By: /s/ E. Linn Draper, Jr.

E. Linn Draper, Jr.
Chief Executive Officer

EXHIBIT 31.2
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Susan Tomasky, certify that:
1. I have reviewed this quarterly report on Form 10-Q of:

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;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) for the registrant and we have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

   b. evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this quarterly report based on such evaluation; and

   c. disclosed in this quarterly report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent function):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 12, 2003

By: /s/ Susan Tomasky

Susan Tomasky
Chief Financial Officer

Exhibit 32.1

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of the Companies (as defined below) on Form 10-Q for the quarterly period ended September 30, 2003 as filed with the Securities and Exchange Commission on the date hereof (the “Reports”), I, E. Linn Draper, Jr., the chief executive officer of

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

(the “Companies”), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ E. Linn Draper, Jr.

E. Linn Draper, Jr.
November 12, 2003

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of the Companies (as defined below) on Form 10-Q for the quarterly period ended September 30, 2003 as filed with the Securities and Exchange Commission on the date hereof (the “Reports”), I, Susan Tomasky, the chief financial officer of

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

(the “Companies”), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Susan Tomasky

Susan Tomasky

November 12, 2003

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

End of Filing