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, 2004
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 of Principal Executive Offices, 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.

	Number of Shares of Common Stock Outstanding at October 29, 2004	Par Value at October 29, 2004
American Electric Power Company, Inc.	395,704,805	$6.50
AEP Generating Company	1,000	1,000
AEP Texas Central Company	2,211,678	25
AEP Texas North Company	5,488,560	25
Appalachian Power Company	13,499,500	-
Columbus Southern Power Company	16,410,426	-
Indiana Michigan Power Company	1,400,000	-
Kentucky Power Company	1,009,000	50
Ohio Power Company	27,952,473	-

Public Service Company of Oklahoma	9,013,000	15
Southwestern Electric Power Company	7,536,640	18

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORT ON FORM 10-Q
September 30, 2004

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
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 AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System Power Pool or AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Cook Plant	The Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
ECAR	East Central Area Reliability Council.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	The Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
GAAP	Generally Accepted Accounting Principles.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IURC	Indiana Utility Regulatory Commission.
JMG	JMG Funding LP.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, an AEP subsidiary.
ME SWEPCo	Mutual Energy SWEPCo L.P., a Texas retail electric provider.
Money Pool	AEP System's Money Pool.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NOx	Nitrogen oxide.
OATT	Open Access Transmission Tariff.
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.
PUCT	The Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
PURPA	The Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
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 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.
SNF	Spent Nuclear Fuel.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by AEP Texas Central Company, an AEP electric utility subsidiary.
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.
True-up Proceeding	A filing to be made under the Texas Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
TVA	Tennessee Valley Authority.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
Zimmer Plant	William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by Columbus Southern Power Company, an AEP subsidiary.

FORWARD-LOOKING INFORMATION

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

o Electric load and customer growth.
o Weather conditions, including storms.
o Available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters.
o Availability of generating capacity and the performance of AEP's generating plants.

- o The ability to recover regulatory assets and stranded costs in connection with deregulation.
- o The ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- o New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
- o Resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments and environmental compliance).
- o Oversight and/or investigation of the energy sector or its participants.
- o Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- o AEP's ability to constrain its operation and maintenance costs.
- o The success of disposing of investments that no longer match AEP's business model.
- o AEP's ability to sell assets at acceptable prices and on other acceptable terms.
- o International and country-specific developments affecting foreign investments including the disposition of any foreign investments.
- o The economic climate and growth in AEP's service territory and changes in market demand and demographic patterns.
- o Inflationary trends.
- o AEP's ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy-related commodities.
- o Changes in the creditworthiness and number of participants in the energy trading market.
- o Changes in the financial markets, particularly those affecting the availability of capital and AEP's ability to refinance existing debt at attractive rates.
- o Actions of rating agencies, including changes in the ratings of debt and preferred stock.
- o Volatility and changes in markets for electricity, natural gas, and other energy-related commodities.
- o Changes in utility regulation, including membership and integration in a regional transmission structure.
- o Accounting pronouncements periodically issued by accounting standard-setting bodies.
- o The performance of AEP's pension and other postretirement benefit plans.
- o Prices for power that AEP generates and sells at wholesale.
- o Changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

EXECUTIVE OVERVIEW

Utility Operations Segment Results

While earnings from our Utility Operations were less than our earnings for the same periods for the prior year, we are pleased with the results. Net income from Utility Operations was $359 million for the third quarter 2004 and $845 million for the nine months ended September 30, 2004. We continue to see healthy utility sales increases in most of our regions due to increased usage and growth in our residential and commercial customer base for the first three quarters of 2004. Additionally, improvements in the economy are reflected in our industrial sales. These favorable trends were not sufficient to offset the absence of the Wholesale Capacity auction revenues in 2004, higher planned plant maintenance and distribution system reliability improvement work, and the impact of unfavorable weather in the third quarter due to a mild summer in 2004.

Progress Made on Asset Sales

We are on schedule with our planned divestiture of various unregulated businesses and other assets and are making significant progress towards completion of the disposal of our interests in AEP Texas Central Company (TCC) generating assets. The proceeds from the sales are being used to reduce existing long-term debt and other obligations. We expect the remaining asset sales to be completed no later than mid 2005.

During the first six months of 2004, we completed (a) the sale of our interest in the Pushan Power Plant in China, (b) the sale of Louisiana Intrastate Gas Pipeline Company, and (c) the sale of the mining operations of AEP Coal.

During the third quarter 2004, we completed (a) the sale of two coal fired plants in the U.K. (Fiddler's Ferry and Ferrybridge) along with related coal inventory and a number of related commodity and freight contracts, (b) the sale of our ownership interests in our two independent power producers in Florida and one in Colorado, and (c) the sale of our 50 percent interest in South Coast Power Limited, owner of the Shoreham Power Station in the U.K.

During October 2004, we completed (a) the sale of Jefferson Island Storage & Hub LLC, including salt dome caverns and pipelines, (b) the sale of our ownership interest in our final independent power producer in Colorado, and (c) the sale of the former headquarters building for CSW in Dallas, Texas.

Unregulated assets that are currently being marketed include (a) our 50 percent interest in Bajio, a 600 MW natural gas-fired generation facility located in Mexico and (b) our 20 percent equity interest in Pacific Hydro, an Australian renewable energy company. We will continue our effort to locate buyers for these assets.

During the third quarter, we sold the majority of TCC's generation assets, including eight natural gas plants, one coal-fired plant and one hydro plant. The remaining TCC generation assets to be sold include TCC's share of the Oklaunion Power Station and TCC's share of the South Texas Project (STP) nuclear plant. Agreements have been reached for the sale of TCC's interest in both facilities and we expect the sales to be completed in the first half of 2005. Nevertheless, there could be potential delays in receiving necessary regulatory approvals and clearances, which could delay the closings. The sale of the TCC assets will allow us to determine stranded costs for recovery under the Texas Legislation.

This year's sales of non-strategic, non-regulated international and domestic assets are consistent with our strategy that focuses on our core domestic utility business.

PJM Integration

We worked closely with regulators in all our states to successfully address issues related to the PJM integration process. As a result of those efforts, we transferred functional control of AEP's eastern transmission grid of nearly 22,300 transmission miles to PJM Interconnection, a regional transmission organization, on October 1, 2004. Our membership in PJM is expected to improve the system reliability throughout the 12-state PJM RTO region.

Environmental

We have announced plans to invest approximately $3.5 billion in capital from 2004 to 2010, and a total of $5 billion through 2020, to install pollution control equipment that preserves the low cost generation from our coal-fired power plants in the East. Fifty-one percent of our $3.5 billion capital plan relates to Ohio generation facilities, followed by Virginia and West Virginia with 35 percent, Kentucky with 9 percent and Indiana with 5 percent. Our overall relationships with regulators are important to our growth strategy and our goal of producing low-cost electricity with minimal impact on the environment. It is important that we manage the regulatory process to ensure that we receive fair recovery of our costs, including capital costs, as we fulfill our commitment to invest in environmental projects at our generating plants.

Overall Regulatory Matters and Regional Reorganization

Refocusing on the regulatory compact is essential to our success and will be one of the main drivers of our performance in the future. The regulatory compact is the means through which we make necessary investments to serve our customers and in return are provided, through regulation, the opportunity to recover our costs including a reasonable return on our investments. Our recent regional reorganization along state and jurisdictional lines reinforces our focus on customer service and aligns management with successful financial outcomes.

Texas Regulatory Activity

Stranded Cost Recovery

We continue to devote a great deal of time and effort to the issue of stranded cost recovery in Texas. We cannot file our case for stranded cost recovery until TCC's generation assets have been sold unless a waiver is granted. TCC is evaluating and may seek a good-cause exception to the true-up rule to allow us to file our True-up Proceedings before the sale of all of our TCC generation assets is completed. The only asset sales pending are our Oklaunion and STP interests. Both should be completed in the first half of 2005. The principal component of the process is the net stranded generation costs (approximately $1.3 billion). Other net regulatory assets may also be recovered through customer transition charges.

The ultimate recovery of these assets is subject to what is expected to be a contentious stranded cost True-up Proceeding. Although we believe that these assets are recoverable under the Texas restructuring legislation, we anticipate that other parties will contend that material amounts of stranded costs should not be recovered. If these contentions are successful, in whole or in substantial part, that would adversely affect future results of operations, cash flows and financial condition.

TCC Rate Case

TCC has a base rate filing before the Public Utility Commission of Texas (PUCT) in which we are requesting an adjusted $41 million rate increase. After hearing the case, the ALJ has recommended a reduction in existing rates of somewhere between $33 million and $43 million depending on the final treatment of consolidated tax savings. We have defended vigorously our request in briefs submitted to the PUCT. Hearings were held on the consolidated tax savings remand issue in September 2004. The PUCT is expected to issue a decision in the fourth quarter of 2004.

Ohio Regulatory Activity

Our strategy to invest capital in environmental assets has particular significance in Ohio, our largest jurisdiction with 11,130 MW of generation and 1.5 million customers. Fifty one percent of our $3.5 billion environmental capital plan is anticipated to be spent in Ohio. We have filed our proposed rate stabilization plan which includes a 7% increase each year for the generation component of the rate for Ohio Power Company customers and a 3% rate increase each year for Columbus Southern Power Company customers beginning in 2006 and ending in 2008. Our plan also offers the option to remove the current residential 5% generation discount earlier than the statutory elimination at the end of 2005 to reduce the annual percentage increase to residential customers. The plan includes the opportunity annually to request an additional increase averaging 4% per year for both companies if costs exceed the currently anticipated level. Our Ohio Companies' Rate Stabilization Plans also provide for the deferral of environmental construction and in-service carrying costs plus PJM RTO administrative fees in 2004 and 2005 for recovery through a wires charge in 2006 through 2008. The plan is designed to recover the cost increases that are expected to result from environmental improvements to our Ohio generating units and the costs of transmission reliability improvements from joining PJM. A non-affiliated utility received an order which rejected its request for automatic increases and deferrals during the Market Development Period (MDP). The PUCO has indicated in FirstEnergy companies' rate stabilization plans that these plans are specific to a company's requirements and characteristics and the PUCO's order in one case should not be considered precedent for another company's rate stabilization plan. Management is unable to predict how the PUCO will rule regarding our rate stabilization filings. The PUCO is expected to issue an order before the end of the 2004.

Energy Costs

Coal, natural gas and oil prices have increased dramatically during 2004. These increasing costs are the result of increasing worldwide demand, supply uncertainty, and transportation constraints, as well as other factors that are not fundamentally observable. We manage price risk, particularly around coal, through long-term purchase contracts, fuel clauses in several jurisdictions and other fuel procurement activities.

Improving Our Balance Sheet

We are utilizing and will continue to utilize the cash generated by the sale of certain assets to reduce existing long-term debt and other obligations. During the nine months ended September 30, 2004, we reduced total long-term debt by approximately $1.5 billion, or 10%. The result of our use of cash on hand and sales proceeds to reduce debt has decreased our debt to total capitalization ratio from 64.6% at December 31, 2003 to 60.8% at September 30, 2004.

New Technology Plant

We intend to build a synthetic-gas-fired plant up to 1,000 MW of capacity in the next five to six years utilizing integrated gasification combined cycle (IGCC) technology. We estimate that this new plant will cost up to $1.6 billion. We have not determined a location for the plant, but it will likely be in one of our eastern states, because of ready access to coal. We will work with state regulators and legislators to establish a framework for recovery of this significant investment in new clean coal technology before site selection. Our significant planned investments in emission control installations at existing coal-fired plants and our commitment to IGCC technology reinforces our belief that coal will be a lower emission energy source of the future and further signals our commitment to investing in clean, environmentally safe technology.

Additional Information

For additional information on our strategic outlook, see "Management's Financial Discussion and Analysis of Results of Operations," including "Business Strategy," in our 2003 Annual Report. Also see the remainder of our "Management's Financial Discussion and Analysis of Results of Operations" in this Form 10-Q, along with the Notes to Consolidated Financial Statements.

RESULTS OF OPERATIONS

Segments

Our principal operating business segments and their major activities are:
o Utility Operations:
o Domestic generation of electricity for sale to retail and wholesale customers.
o Domestic electricity transmission and distribution.

o Investments-Gas Operations:*
o Gas pipeline and storage services.

o Investments-UK Operations:**
o International generation of electricity for sale to wholesale customers.
o Coal procurement and transportation to our U.K. plants.

o Investments-Other:***
o Bulk commodity barging operations, windfarms, independent power producers and other energy supply related businesses.

* Operations of Louisiana Intrastate Gas, including Jefferson Island Storage, were classified as discontinued during 2003 and were sold during the second and fourth quarter 2004, respectively. ** UK Operations were classified as discontinued during 2003 and were sold during third quarter 2004. *** Four independent power producers were sold during the third and fourth quarter 2004.

There are numerous changes occurring in the businesses included in our segments as a result of our continued divestiture of certain non-core operations. Substantially all operations and assets within our Investments - UK Operations segment were sold in July 2004. Within our Investments - Gas Operations segment, we have recently sold LIG Pipeline Company, which included our gas pipeline portion of Louisiana Intrastate Gas, and Jefferson Island Storage & Hub, L.L.C., which included our Louisiana gas storage assets held for sale. The only substantive portion of the Investments - Gas Operations business that remains is our Houston Pipe Line Company L.P. (HPL) operations, which includes the Bammel storage facility and related pipeline assets. We will continue to operate HPL as we evaluate our future plans for this investment.

In addition, there have been numerous divestitures of businesses, assets and investments within our Investments - Other segment over the course of the past nine months including AEP Coal and our interest in the Pushan Power Plant. We also completed the sale of three independent power producers during the third quarter 2004 and closed on the sale of a fourth independent power producer facility early in the fourth quarter 2004. Our investment in South Coast Power Limited, owner of the Shoreham Power Station in the U.K., was also sold in the third quarter 2004. Our goal for the remaining assets in this segment, which includes our unregulated investments in wind farms, and barging and river transportation groups, is to operate them in such a way that they complement our core capabilities in regulated utility operations.

All of the changes in these segments are leading us to review our business model of the future and how we intend to manage our business overall. The decisions we make over the course of the remainder of the year may lead to changes in our reported business segments.

AEP Consolidated Results

Our consolidated Net Income for the three and nine month periods ended September 30, 2004 and 2003 was as follows (Earnings and Average Shares Outstanding in millions):

	Third Quarter				Nine Months Ended September 30,			
	2004		2003		2004		2003	
	Earnings	EPS	Earnings	EPS	Earnings	EPS	Earnings	EPS
Utility Operations	$359	$0.90	$409	$1.03	$845	$2.13	$940	$2.46
Investments - Gas Operations	(28)	(0.07)	(21)	(0.05)	(41)	(0.10)	(64)	(0.17)
Investments - Other	90	0.23	(45)	(0.11)	91	0.23	(45)	(0.12)
All Other*	(9)	(0.02)	(36)	(0.09)	(43)	(0.11)	(54)	(0.14)
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	412	1.04	307	0.78	852	2.15	777	2.03
Investments - Gas Operations	(3)	-	2	-	(2)	-	6	0.01
Investments - UK Operations	120	0.30	(52)	(0.13)	56	0.14	(89)	(0.23)
Investments - Other	1	-	-	-	6	0.01	(15)	(0.04)
Discontinued Operations	118	0.30	(50)	(0.13)	60	0.15	(98)	(0.26)
Utility Operations	-	-	-	-	-	-	236	0.62
Investments - Gas Operations	-	-	-	-	-	-	(22)	(0.06)
Investments - UK Operations	-	-	-	-	-	-	(21)	(0.05)
Cumulative Effect of Accounting Changes	-	-	-	-	-	-	193	0.51
Total Net Income	$530	$1.34	$257	$0.65	$912	$2.30	$872	$2.28
Average Shares Outstanding		396		395		396		382

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

Third Quarter 2004 Compared to Third Quarter 2003

Income Before Discontinued Operations and Cumulative Effect of Accounting Changes increased $105 million to $412 million in third quarter 2004 compared to third quarter 2003. Net Income for third quarter 2004 of $530 million or $1.34 per share includes a gain, net of taxes, from discontinued operations of $118 million. Net Income for third quarter 2003 of $257 million or $0.65 per share includes a loss, net of taxes, from discontinued operations of $50 million.

For the third quarter 2004 our Utility Operations Earnings decreased $50 million, or 12%, from the previous year driven primarily by the absence of the Texas wholesale capacity auction true-up revenue in 2004 and milder weather in the summer months of 2004 offset by higher industrial load growth.

Earnings from our UK Operations (which were sold on July 30, 2004) improved $172 million in the third quarter 2004 as compared to the same period in 2003 primarily due to a gain of $127 million, net of tax, on the sale. These operations had impairment losses in 2003. Please refer to our 2003 Annual Report for further discussion.

Earnings from our Gas Operations decreased $12 million from the previous year reflecting a decrease in results from storage-related gas valuation losses, which we expect will reverse in future periods.

Earnings from our Investments - Other segment increased $136 million. This segment benefited from the sale of three of our IPP investments and the sale of our 50 percent interest in South Coast Power Limited, owner of the Shoreham Power Station in the U.K. in 2004 compared to the same period in 2003, which included impairments on the IPPs. We recorded $95 million in gains from the sale of these investments during the third quarter 2004.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Income Before Discontinued Operations and Cumulative Effect of Accounting Changes increased $75 million to $852 million in 2004 compared to 2003. Net Income for 2004 of $912 million or $2.30 per share includes a gain, net of taxes, from discontinued operations of $60 million. Net Income for 2003 of $872 million or $2.28 per share includes a loss, net of taxes, from discontinued operations of $98 million and a benefit from a net $193 million of cumulative effect of changes in accounting related to asset retirement obligations and accounting for risk management contracts.

For the nine months ended September 30, 2004, Utility Operations Income Before Discontinued Operations and Cumulative Effect of Accounting Changes decreased $95 million or 10% from the previous year primarily due to the absence of the Texas wholesale capacity auction true-up revenue in 2004.

Reduced losses at our UK Operations, included in discontinued operations, were responsible for $166 million (including cumulative effect of accounting changes) of the increase in Net Income in 2004. In July 2004, we completed the sale of substantially all operations and assets within our Investments - UK Operations segment resulting in a gain of $127 million, net of tax, on the sale. These operations had impairment losses in 2003. Please refer to our 2003 Annual Report for further discussion.

Our Investments - Gas Operations segment posted a lower loss in 2004 due to improved pipeline operations and lower operating expenses.

Our results of operations by operating segment are discussed below.

Utility Operations

	Third Quarter 2004	Third Quarter 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(in millions)			
Revenues	$2,946	$3,112	$8,095	$8,483
Fuel and Purchased Power	1,054	1,121	2,635	2,967
Gross Margin	1,892	1,991	5,460	5,516
Depreciation and Amortization	322	317	940	927
Other Operating Expenses	895	899	2,806	2,659
Operating Income	675	775	1,714	1,930
Other Income (Expense), Net	7	15	32	18
Interest Charges and Preferred Stock Dividend Requirements	151	168	471	499
Income Tax Expense	172	213	430	509
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	$359	$409	$845	$940

Summary of Selected Sales Data
For Utility Operations

	Third Quarter 2004	Third Quarter 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
Energy Summary		(in millions of KWH)		
Retail:				
Residential	12,002	12,578	35,169	34,658
Commercial	10,070	10,267	28,240	27,834
Industrial	13,052	12,309	38,227	36,764
Miscellaneous	857	827	2,406	2,251
Subtotal	35,981	35,981	104,042	101,507
Texas Retail and Other	316	725	802	2,264
Total	36,297	36,706	104,844	103,771

Wholesale:	23,613	19,669	62,838	56,385
	=======	=======	========	========

Summary of Selected Data
For Utility Operations

	Third Quarter		Nine Months Ended September 30,	
	2004	2003	2004	2003
Weather Summary	(in degree days)			
Eastern Region				
Actual - Heating	1	12	2,032	2,181
Normal - Heating*	7		1,993	1,979
Actual - Cooling	553	592	869	750
Normal - Cooling*	679		960	962
Western Region (PSO/SWEPCo)				
Actual - Heating	0	0	913	1,074
Normal - Heating*	2		1,013	1,006
Actual - Cooling	1,178	1,390	1,867	2,034
Normal - Cooling*	1,398		2,058	2,050

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

Third Quarter 2004 Compared to Third Quarter 2003

Reconciliation of Third Quarter 2003 to Third Quarter 2004
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes
(in millions)

Third Quarter 2003		$409
Changes in Gross Margin:		
Retail Margins	(2)	

Texas Supply	(10)	
Wholesale Capacity Auction Revenues	(61)	
Off-System Sales	(26)	
	----	
		(99)
Changes in Operating And Other Expenses:		
Operations and Maintenance	(3)	
Depreciation and Amortization	(5)	
Taxes, Other	7	
Other Income (Expense), Net	(8)	
Interest Charges	17	

		8
Income Tax Expense		41

Third Quarter 2004		$359
		=====

Income from Utility Operations decreased $50 million to $359 million in 2004. The key driver of the decrease was a $99 million decrease in gross margin partially offset by an $8 million net decrease in operating and other expenses, and a $41 million decrease in income taxes.

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

o Overall retail margins in our utility business were slightly below last year. Residential demand decreased from the prior year as a result of lower usage by customers due to mild weather in the summer months of 2004 across most of the service territory. Cooling degree days were down in both the East and the West as compared to the prior year. Partially offsetting the mild weather were favorable results from residential and commercial customer growth and increased demand in industrial classes from the continuing economic recovery in our regions.
o Our Texas supply business had a $10 million decrease in gross margin as a result of increased purchased power costs due to the divestiture of assets, and pursuant to our energy supply commitments we made to our wholesale customers, at the end of the second quarter of 2004.
o Beginning in 2004, the wholesale capacity auction true-up ceased per rules of the PUCT. Related revenues are no longer recognized, resulting in $61 million of lower regulatory deferrals in 2004. For the years 2003 and 2002, we recognized revenues for the wholesale capacity auction true-up for TCC as a regulatory asset for the difference between the actual market prices based upon the state-mandated auction of 15% of generation capacity and the earlier estimate of market price used in the PUCT's excess cost over market model.
o Margins from off-system sales for 2004 were $26 million lower than 2003 primarily due to lower optimization activity.

Utility Operating and Other Expenses changed between years as follows:

o Interest expense decreased $17 million due to the refinancing of higher coupon debt and the retirement of debt.
o Income Tax expense decreased $41 million largely due to the decrease in pre-tax income and other tax return adjustments.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Reconciliation of Nine Months Ended September 30, 2003 to Nine Months Ended September 30, 2004
Income Before Discontinued Operations & Cumulative Effect of Accounting Changes
(in millions)

Nine Months Ended September 30, 2003	$940

Changes in Gross Margin:		
Retail Margins	119	
Texas Supply	(52)	
Wholesale Capacity Auction Revenues	(169)	
Off-System Sales	34	
Other	12	
		(56)
Changes in Operating And Other Expenses:		
Operations and Maintenance	(138)	
Depreciation and Amortization	(13)	
Taxes, Other	(9)	
Other Income (Expense), Net	14	
Interest Charges	28	
		(118)
Income Tax Expense		79
Nine Months Ended September 30, 2004		$845

Income from Utility Operations, before a $236 million cumulative effect of accounting changes in 2003, decreased $95 million in 2004 to $845 million. Key drivers of the change include $118 million increase in operating and other expenses, a $56 million decrease in gross margin and a $79 million decrease in income taxes.

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

o Overall retail margins (excluding fuel recovery) in our utility business increased $60 million. Demand in the East and the West increased over the prior year as a consequence of higher usage in most classes and customer growth in the residential and commercial classes. Commercial and industrial demand also increased resulting from the economic recovery in our regions. Milder weather during the summer months of 2004 partially offset these favorable results.
o Fuel recovery in our non-Texas utility operations was a net $59 million favorable in comparison to last year due to higher fuel costs in the prior year resulting primarily from the conclusion of the amortization of deferred Cook plant outage costs and a fish intrusion outage causing us to purchase higher priced non-nuclear replacement power in 2003.
o Our Texas supply business had a $52 million decrease in gross margin principally due to the divestiture of TCC generation assets to comply with Texas stranded cost recovery regulations. This resulted in higher purchased power costs to fulfill contractual commitments.
o Beginning in 2004, the wholesale capacity auction true-up ceased per rules of the PUCT. Related revenues are no longer recognized, resulting in $169 million of lower regulatory deferrals in 2004. For the years 2003 and 2002, we recognized the revenues for the wholesale capacity auction true-up for TCC as a regulatory asset for the difference between the actual market prices based upon the state-mandated auction of 15% of generation capacity and the earlier estimate of market price used in the PUCT's excess cost over market model.
o Margins from off-system sales for 2004 were $34 million better than in 2003 due to favorable optimization activity, somewhat offset by lower volumes.

Utility Operating and Other Expenses changed between years as follows:

o Maintenance and Other Operation expense increased $138 million due to a $67 million increase in generation expenses primarily due to the timing of planned plant outages in 2004 as compared to 2003, and increases in related chemical expenses. Additionally, distribution maintenance expense increased $39 million from system reliability work. Other increases of $22 million include employee benefits, insurance, and other administrative and general expenses, magnified by favorable adjustments in 2003. These increases were offset, in part, by $30 million due to the conclusion of the amortization of our deferred Cook nuclear plant restart settlement expenses. Expenses of $40 million, comprised of various miscellaneous items, make up the remainder of the increase.
o Depreciation and amortization expense increased $13 million primarily due to a higher depreciable asset base, including the addition

of capitalized software costs, increased amortization of regulatory assets, and the consolidation of JMG at Ohio Power (which had no impact on net income). These increases more than offset the decrease in expense at AEP Texas Central, which is due primarily to the cessation of depreciation on plants classified as held for sale.

o Taxes other than income taxes increased $9 million due to increased property tax values and assessments.
o Interest expense decreased $28 million from the prior period due to the refinancings of higher coupon debt.
o Income Tax expense decreased $79 million due to the decrease in pre-tax income and other prior year tax return adjustments.

Investments - Gas Operations

	Third Quarter		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(in millions)			
Revenues	$746	$773	$2,214	$2,396
Purchased Gas	739	747	2,124	2,321
Gross Margin	7	26	90	75
Maintenance and Other Operation	34	40	94	114
Other Operating Expenses	3	-	9	11
Operating Loss	(30)	(14)	(13)	(50)
Other Income (Expense), Net	-	(3)	(9)	(8)
Interest Expense	14	15	39	41
Income Tax Benefit	16	11	20	35
Net Loss Before Discontinued Operations and Cumulative Effect of Accounting Changes	$(28)	$(21)	$(41)	$(64)

Third Quarter 2004 Compared to Third Quarter 2003

Our $28 million loss from Gas Operations before discontinued operations and cumulative effect of accounting changes compares with a $21 million loss recorded in the third quarter of 2003. Gross margins decreased $19 million year-over-year primarily due to valuation changes on price risk management of fully-hedged physical gas inventories. As gas was injected into storage during the spring and summer, we hedged the price risk by selling corresponding quantities in the winter months. As compared to the prior year, we recognized storage related valuation losses of approximately $23 million on these fully-hedged positions, which will reverse as margins are recognized when gas is withdrawn and delivered in future periods. Operating expenses increased by $3 million. Income tax benefits increased by $5 million due to the decrease in pre-tax income.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Our $41 million loss from Gas Operations before discontinued operations and cumulative effect of accounting changes compares with a $64 million loss recorded in the year-to-date September 2003 period. Gross margins improved $15 million year-to-date September 30, 2004 to $90 million. As compared to the prior year, current year margins have been reduced by $25 million due primarily to valuation changes on fully-hedged inventory positions, which will reverse as margins are recognized when gas is withdrawn and delivered in future periods. Without this impact, margins would have been approximately $40 million higher in the first nine months 2004 than the first nine months of 2003. This was driven by $20 million of significant losses in 2003 from servicing a single contract, improved earnings from the pipeline operations, and the avoidance of prior year margin losses from the eliminated trading activities. In addition, operating expenses decreased $22 million between periods as a result of gas trading activities which have been eliminated and lower depreciation resulting from 2003 asset impairments. Income tax benefits decreased by $15 million primarily due to the improvement in pre-tax income.

Investments - UK Operations

Third Quarter 2004 Compared to Third Quarter 2003

Net income from our Investments - UK Operations segment (all classified as Discontinued Operations) increased to $120 million in income, which includes a gain on sale of $127 million in 2004, compared with a loss of $52 million in 2003. During late 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. In July 2004, we completed the sale of substantially all operations and assets within our Investments - UK Operations segment. Included in the sale are the generating assets, commodity contracts, including electricity sales contracts, coal purchase and sale contracts and freight contracts with a number of different market counterparties for varying contract periods. The remaining assets and liabilities include certain coal, power and capacity positions and financial coal and freight swaps. The majority of these positions will either mature or be settled with the applicable counterparties during the fourth quarter 2004.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Income from our Investments - UK Operations segment (all classified as Discontinued Operations) increased to $56 million in income, which includes a gain on sale of $127 million in 2004, compared with a loss of $89 million in 2003, before the cumulative effect of accounting change. During late 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. In July 2004, we completed the sale of substantially all operations and assets within our Investments - UK Operations segment.

Investments - Other

Third Quarter 2004 Compared to Third Quarter 2003

Income before discontinued operations and cumulative effect of accounting changes from our Investments - Other segment increased by $135 million in 2004, primarily due to an after-tax gain of approximately $64 million resulting from the sale in July 2004 of our ownership interests in our two independent power producers (IPPs) in Florida (Mulberry and Orange), and one in Colorado (Brush II), and an after-tax gain of approximately $31 million resulting from the sale of our 50 percent interest in South Coast Power Limited, owner of the Shoreham Power Station in the UK. In addition, results in the current quarter did not include a $45 million after-tax impairment in the third quarter of 2003, related to our investment in the IPPs.

The above increases were primarily offset by a $2 million decrease in results at our MEMCO operations due primarily to operational items and a $3 million decrease at our IPPs and windfarms, resulting primarily from the sale of three of our IPPs in the third quarter 2004.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003
Income before discontinued operations and cumulative effect of accounting changes from our Investments - Other segment increased from a loss of $45 million to $91 million of income in 2004.

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

o We recorded an after-tax gain of approximately $64 million resulting from the sale in July 2004 of our ownership interests in our two independent power producers in Florida (Mulberry and Orange),
o We recorded an after-tax gain of approximately $31 million resulting from the sale of our 50% interest in South Coast Power Limited, owner of the Shoreham Power Station in the U.K.,
o Our results in 2004 did not include a $45 million after-tax impairment in the third quarter of 2003, related to our investment in the Colorado IPPs.
o Our results at our MEMCO operations increased $2 million in 2004 due to a stronger freight market in the nine month period in 2004 as compared to 2003.
o Our AEP Texas Provider of Last Resort (POLR) entity recorded a $6 million provision for uncollectible receivables in the first six months of 2003 that did not recur in 2004,
o Our AEP Resources entity decreased its loss by $17 million in 2004 versus 2003, primarily due to lower interest expense resulting from equity capital infusions in mid and late 2003 that were used to reduce debt and other corporate borrowings, and
o Our AEP Pro Serv entity reduced losses from $4 million to break even, primarily due to operations winding down in 2004.

Offsetting these increases was the absence during 2004 of a $31 million nonrecurring gain recorded in the first quarter of 2003 primarily related to a gain from the sale of Mutual Energy and a $2 million decrease in results at our IPPs and windfarms resulting primarily from the sale of three of our IPPs in the third quarter 2004.

In discontinued operations, the Eastex Cogeneration facility near Longview, Texas was sold in the third quarter 2003 and Pushan Power Plant was sold in March 2004.

All Other

Third Quarter 2004 Compared to Third Quarter 2003

Our parent company's third quarter 2004 expenses decreased $27 million from the level in the third quarter of 2003 due to a $23 million net decrease in expenses primarily resulting from lower general advertisement expenses in 2004 and a non-recurring, unfavorable receivable write-off in the prior period. Interest expense was $6 million lower in the current period due to lower fixed rate financing and buy back of parent bonds, and parent guarantee fee income from subsidiaries was lower by $2 million compared to the prior period.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Our parent company's year-to-date 2004 expenses decreased $11 million from the level in the year-to-date period of 2003 due to a $28 million net decrease in expenses primarily resulting from lower insurance premiums and lower general advertisement expenses in 2004 and a non-recurring, unfavorable receivable write-off in the prior period. Interest income was $12 million lower in the current period due to lower money pool and cash balances along with higher interest rates on invested funds in 2003. Additionally, parent guarantee fee income from subsidiaries was lower by $5 million compared to the prior period due to the reduction of trading activities.

Income Taxes

The effective tax rates for the third quarter of 2004 and 2003 were 33.0% and 35.8% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, energy production credits, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to federal income tax return adjustments.

The effective tax rates for the first nine months of 2004 and 2003 were 34.1% and 35.4% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, energy production credits, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows.

Capitalization

	September 30, 2004	December 31, 2003
Common Equity	38.9%	35.1%
Preferred Stock	0.3	0.3
Preferred Stock (Subject to Mandatory Redemption)	0.3	0.3
Long-term Debt, including amounts due within one year	59.5	62.8
Short-term Debt	1.0	1.5
Total Capitalization	100.0%	100.0%

Our $2.3 billion in cash flows from operations, combined with our reduction in cash expenditures for investments in discontinued operations, the proceeds from asset sales, a reduction in the dividend beginning in the second quarter of 2003 and the use of a portion of our cash on hand, allowed us to reduce long-term debt by $1.5 billion and short-term debt by $112 million.

Our common equity increased due to the issuance of $13 million of new common equity (related to our incentive compensation plans) and the fact that our earnings exceeded our dividends for the nine months ended September 30, 2004.

As a consequence of the capital changes during the nine months, we improved our ratio of debt to total capital from 64.6% to 60.8% (preferred stock subject to mandatory redemption is included in debt component of ratio).

Liquidity

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

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. We had an available liquidity position, at September 30, 2004, of approximately $4 billion as illustrated in the table below.

	Amount	Maturity
	(in millions)	
Commercial Paper Backup:		
Lines of Credit	$1,000	May 2005
Lines of Credit	750	May 2006
Lines of Credit	1,000	May 2007
Letter of Credit Facility	200	September 2006
Total	2,950	
Cash and Cash Equivalents	1,282	
Total Liquidity Sources	4,232	
Less: AEP Commercial Paper Outstanding	180(a)	
Letters of Credit Outstanding	36	
Net Available Liquidity at September 30, 2004	$4,016	

(a) Amount does not include JMG Funding LP commercial paper outstanding in the amount of $20 million. This commercial paper is specifically associated with the Gavin scrubber lease and does not reduce available liquidity to AEP. The JMG Funding LP commercial paper is supported by a separate letter of credit facility not included above.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At September 30, 2004, we were in compliance with the covenants contained in these credit agreements and contractual debt to total capitalization was 56.2%. Non-performance of these covenants could result in an event of default under these credit agreements. In addition, the acceleration of our payment obligations, or certain obligations of our subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the amounts outstanding to be payable.

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

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

Money pool and external borrowings may not exceed SEC or state commission authorized limits. At September 30, 2004, we had not exceeded the SEC or state commission authorized limits.

Credit Ratings

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

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

Our current ratings by the major agencies are as follows:

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

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

Common Stock Dividends

After the completion of our planned divestitures and after the results of our Ohio and Texas rate proceedings are known, we hope to be able to recommend to the Board of Directors a modest increase in our common stock dividend from its current quarterly level of 35 cents per share.

Cash Flow

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

	Nine Months Ended September 30,	
	2004	2003
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$976	$1,084
Net Cash Flows From Operating Activities	2,265	1,756
Net Cash Flows From (Used For) Investing Activities	130	(1,540)
Net Cash Flows From (Used For) Financing Activities	(2,089)	320
Net Increase in Cash and Cash Equivalents	306	536
Cash and Cash Equivalents at End of Period	$1,282	$1,620

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provide necessary working capital and help us meet other short-term cash needs.

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a utility money pool, which funds the utility subsidiaries, and a non-utility money pool, which funds the majority of the non-utility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of our other subsidiaries that are not participants in the non-utility money pool. As of September 30, 2004, we had credit facilities totaling $2.75 billion to support our commercial paper program. At September 30, 2004, we had $214 million outstanding in short-term borrowings of which $180 million was commercial paper supported by the revolving credit facilities. In addition, JMG had commercial paper outstanding in the amount of $20 million. This commercial paper is specifically associated with the Gavin scrubber lease and is not supported by our credit facilities. The maximum amount of commercial paper outstanding during the quarter ended September 30, 2004 was $529 million.

The weighted-average interest rate for our commercial paper during the third quarter 2004 was 2.05%.

We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding alternatives are arranged. Sources of long-term funding include issuance of common stock, preferred stock or long-term debt and sale-leaseback or leasing agreements.

Operating Activities

	Nine Months Ended September 30, 2004	2003
	(in millions)	
Net Income	$912	$872
Discontinued Operations	(60)	98
Income from Continuing Operations	852	970
Noncash Items Included in Earnings	1,223	1,033
Changes in Assets and Liabilities	190	(247)
Net Cash Flows From Operating Activities	$2,265	$1,756

2004 Operating Cash Flow

Our cash flows from operating activities were $2.3 billion for the first nine months of 2004. We produced income from continuing operations of $852 million during the period. Income from continuing operations for the period included noncash expense items of $1.1 billion for depreciation, amortization and deferred taxes. In addition, there is a current period favorable impact for a net $89 million balance sheet change for risk management contracts that are marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are an increase in the balance of fuel, materials and supplies of $83 million and an increase in the balance of accrued taxes of $388 million.

2003 Operating Cash Flow

Our cash flows from operating activities were $1.8 billion for the first nine months of 2003. We produced income from continuing operations of $970 million during the period. Income from continuing operations for the period included noncash items of $1.2 billion for depreciation, amortization, and deferred taxes, offset by $193 million related to the cumulative effect of accounting changes. There was a current period unfavorable impact for a net $124 million balance sheet change for risk management contracts that were marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. Other activity in the asset and liability accounts related to the wholesale capacity auction true-up asset (ECOM) of $169 million, an increase in customer deposits and risk management collateral of $102 million and changes in accounts receivable and accounts payable of $267 million.

Investing Activities

Nine Months Ended September 30,

	2004	2003
	(in millions)	
Construction Expenditures	$(1,034)	$(936)
Change in Other Cash Deposits, Net	27	36
Investment in Discontinued Operations, net	(59)	(686)
Proceeds from Sales of Assets	1,202	49
Other	(6)	(3)
Net Cash Flows From (Used for) Investing Activities	$130	$(1,540)

Our cash flows used for investing activities decreased $1.7 billion from the same period in the prior year primarily due to proceeds from the sales of assets in 2004 and investments made in our U.K. operations during 2003 that did not recur during 2004.

Financing Activities

	Nine Months Ended September 30, 2004	2003
	(in millions)	
Issuances of Common Stock	$13	$1,142
Issuances/Retirements of Debt, net	(1,683)	(116)
Retirement of Preferred Stock	(4)	(2)
Retirement of Minority Interest	-	(225)
Dividends	(415)	(479)
Net Cash Flows From (Used for) Financing Activities	$(2,089)	$320

Our cash flow from financing activities in 2004 decreased $2.4 billion from the $320 million net cash inflow recorded in 2003. During the first quarter of 2003, we issued common stock for $1.1 billion and subsequent to the first quarter of 2003, we reduced our dividend. This compares to only $13 million of cash proceeds from the issuance of common stock under our incentive compensation plans in the first nine months of 2004.

During the first nine months of 2004, we used approximately $1.9 billion of cash to retire long-term debt. We also issued approximately $425 million of long-term debt ($416 million net of issuance costs) including $222 million of pollution control bonds (installment purchase contracts). These activities were supported by the generation of $2.3 billion in cash flow from operations. See Note 10 "Financing Activities" for further information regarding issuances and retirements of debt instruments during the first nine months of 2004.

Off-balance Sheet Arrangements

We enter into off-balance sheet arrangements for various business reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our current policy restricts the use of off-balance sheet financing entities or structures, except for traditional operating lease arrangements and sales of customer accounts receivable that we enter in the normal course of business. Our off-balance sheet arrangements have not changed significantly from year-end. For complete information on each of these off-balance sheet arrangements see the "Minority Interest and Off-balance Sheet Arrangements" in "Management's Financial Discussion and Analysis of Results of Operations" section of the 2003 Annual Report.

Other

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004. The initial term of our lease with Juniper (Juniper Lease) commenced on March 18, 2004 and terminates on June 17, 2009. We may extend the term of the Juniper Lease for up to 30 years. Our lease of the Facility is reported as an owned asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on AEP's balance sheet.

Juniper is an unaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing.

At September 30, 2004, Juniper's acquisition costs for the Facility totaled $520 million, and we estimate total costs for the completed Facility to be approximately $525 million, funded through long-term debt financing of $494 million and equity of $31 million from investors with no relationship to AEP or any of AEP's subsidiaries. For the initial 5-year lease term, the base lease rental is equal to the interest on Juniper's debt financing at a variable rate indexed to three-month LIBOR (1.975% on September 30, 2004) plus 100 basis points, plus a fixed return on Juniper's equity investment in the Facility and certain other fixed amounts. Consequently, as LIBOR increases, the base rental payments under the Juniper Lease will also increase.

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

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

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

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

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

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

SIGNIFICANT MATTERS

Progress Made on Announced Divestitures

We are continuing with our announced plan to divest significant components of our non-regulated assets, including certain domestic and international unregulated generation, part of our gas pipeline and storage business, a coal business and certain IPPs. In addition to the following discussion, see Note 7 of our Notes to Consolidated Financial Statements within this Form 10-Q.

Pushan Power Plant

In December 2003, we signed an agreement to sell our interest in the Pushan Power Plant in Nanyang, China to our minority interest partner. The sale was completed in March 2004 and the effect of the sale on our first quarter results of operations was not significant.

Texas Generation

We made progress on our planned divestiture of certain Texas generation assets by (1) announcing in June 2004 and September 2004 that we had signed agreements to sell TCC's 7.81% share of the Oklaunion Power Station to two unaffiliated co-owners of the plant for approximately $43 million, subject to closing adjustments, (2) announcing in September 2004 that we had signed agreements to sell TCC's 25.2% share of the STP nuclear plant to two unaffiliated co-owners of the plant for approximately $333 million, subject to closing adjustments, and

(3) in July 2004 closing on the sale of TCC's remaining generation assets, including eight natural gas plants, one coal-fired plant and one hydro-electric plant for approximately $425 million, net of adjustments. We expect the sales of Oklaunion and STP to be completed by in the first half of 2005. Nevertheless, there could be potential delays in receiving necessary regulatory approvals and clearances and there could be delays in resolving litigation with a third party affecting Oklaunion which could delay the closings. We will file with the PUCT to recover net stranded costs associated with the sales pursuant to Texas restructuring legislation. Stranded costs will be calculated on the basis of all generation assets, not individual plants.

AEP Coal

As a result of our decision to exit our non-core businesses, we retained an advisor in 2003 to facilitate the sale of AEP Coal. In March 2004, we reached an agreement to sell assets, exclusive of certain reserves and related liabilities, of the mining operations of AEP Coal. The sale closed in April 2004 and the effect of the sale on second quarter 2004 results of operations was not significant.

Gas Operations

In February 2004, we signed an agreement to sell LIG Pipeline Company, which contained the pipeline and processing assets of Louisiana Intrastate Gas (LIG). The sale was completed in early April 2004 and the impact on results of operations in the second quarter of 2004 was not significant. In October 2004, we completed the sale of Jefferson Island Storage & Hub, L.L.C., the remaining LIG gas storage entity. The sale resulted in an additional $12.3 million pre-tax loss ($2 million, net of tax) recorded in the third quarter 2004. We continue to evaluate the merits of retaining or selling our interest in Houston Pipe Line Company L.P., including the Bammel storage facility, which is part of our Investments - Gas Operations segment.

IPP Investments

During the third quarter of 2003, we initiated an effort to sell four domestic IPP investments. In accordance with accounting principles generally accepted in the United States of America, we were required to measure the impairment of each of these four investments individually. Based on studies using market assumptions, which indicated that two of the facilities had market values in excess of book value and two facilities had declines in fair value below book value that were other than temporary in nature, we recorded an impairment of $70 million pre-tax ($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 planned sale of our interest in these IPPs.

In March 2004, we entered into an agreement to sell the four domestic IPP investments for a sales price of $156 million, subject to closing adjustments. An additional pre-tax impairment of $1.6 million was recorded in June 2004 to decrease the carrying value of the Colorado plant investments to their estimated sales price, less selling expenses. We closed on the sale of the two Florida investments and the Brush II plant in Colorado in July 2004, resulting in a pre-tax gain of $104.6 million ($63.8 million, net of tax), generated primarily from the sale of the two Florida IPPs which were not originally impaired. We recorded the gain during July 2004. The sale of the Ft. Lupton, Colorado plant closed in October 2004 and will not have a significant effect on results of operations for the fourth quarter 2004.

UK Operations

In July 2004, we completed the sale of substantially all operations and assets within our Investments - UK Operations segment for approximately $456 million. The sale included Fiddler's Ferry, a coal-fired power plant in northwest England, Ferrybridge, a coal-fired power plant in northeast England, related coal inventories, and a number of related commodities and freight contracts. The sale resulted in a pre-tax gain of $265.6 million ($127.6 million, net of tax).

South Coast Power Limited

In September 2004, we completed the sale of our 50% ownership in South Coast Power Limited for $46.9 million, resulting in a $47.6 million net gain ($30.9 million, net of tax) in the third quarter 2004. The gain reflects improved conditions in the U.K. power market.

Other

We continue to have discussions with various parties on business alternatives for certain of our other non-core investments, which may result in further dispositions in the future.

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

Texas Regulatory Activity

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

The Texas Legislation, among other things:
o provides for the recovery of generation-related regulatory assets and other stranded generation costs through securitization and non-bypassable wires charges,
o requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility,
o provides for an earnings test for each of the years 1999 through 2001 and,
o provides for a stranded cost True-up Proceeding after January 10, 2004.

The True-up Proceedings will determine the amount and recovery of:
o stranded generation plant costs and generation-related regulatory assets including any unrefunded accumulated excess earnings (net stranded generation costs),
o carrying charges on true-up-amounts from January 1, 2002 (the commencement date of retail competition),
o a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up),
o final approved deferred fuel balance,
o excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
o and other true-up items.

TCC's recorded net regulatory asset for amounts subject to approval in the True-up Proceeding is approximately $1.5 billion at September 30, 2004 of which $1.3 billion represents net stranded generation costs.

In September 2004, the PUCT held true-up hearings for another utility, CenterPoint Energy, Inc. (CenterPoint). In that case the PUCT is expected to issue an order later in November 2004 addressing numerous items and that decision may provide indications of possible PUCT actions in TCC's true-up proceedings including:
o the methodology for calculating the recoverable carrying cost related to the True-up Proceedings,
o whether to and how to modify the calculation of the wholesale capacity auction true-up, and
o whether the amount of depreciation in the ECOM model on generation assets for 2002 and 2003 used to calculate the wholesale capacity auction true-up is a recovery of net stranded generation costs and should reduce the recoverable cost. The total TCC depreciation in the ECOM model for the 2002-2003 period was $238 million.

When TCC's True-up Proceeding is completed, TCC currently intends to file to recover PUCT-approved net stranded generation costs and other recoverable true-up amounts that are in excess of current securitized amounts, plus appropriate carrying charges, through a non-bypassable competition transition charge in the regulated T&D rates. TCC may seek to securitize the approved net stranded generation costs plus related carrying costs. The annual costs of securitization are recoverable through a non-bypassable transition charge collected by the T&D utility over the term of the securitization bonds.

TCC will seek to recover in the True-up Proceeding an amount in excess of the $1.5 billion recorded net true-up regulatory asset through September 30, 2004. This is primarily due to TCC not having accrued a carrying cost on its net regulatory asset due to litigation and uncertainties associated with the treatment and measurement of such amounts by the PUCT. Management expects that its review of the final order in the CenterPoint case will resolve numerous uncertainties about applicable PUCT positions and that TCC will be able to record a carrying cost in the fourth quarter of 2004.

Due to the preliminary nature of the pending CenterPoint proceedings and the consequent uncertainty, differences between CenterPoint's and TCC's facts and circumstances and the lack of direct applicability of the CenterPoint proceeding to TCC's recorded assets, we cannot, at this time, determine whether disallowances that may be applicable to CenterPoint would be applicable to TCC. We believe that our recorded regulatory assets are in compliance with Texas Legislation and we intend to seek vigorously recovery of all of these amounts. If, however, we determine that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.5 billion, and we are able to estimate the amount of such non-recovery, we will record a provision for such amount which could have a material adverse effect on future results of operations, cash flows and possible financial condition. To the extent decisions in the TCC True-up Proceeding differ from management expectations based in part on our evaluation of the final CenterPoint decision, additional material disallowances are possible.

In another matter before the PUCT, TCC has filed for an adjusted $41 million base rate increase in its retail distribution rates. After hearing the case the ALJ has recommended a reduction in existing rates of somewhere between $33 million and $43 million depending on the final treatment of consolidated tax savings and other remanded issues. We defended vigorously the Company's requested increase and challenged the ALJ's recommendation in a brief. Hearings were held on the consolidated tax savings remand issue in September 2004. The PUCT is expected to issue a decision in the fourth quarter of 2004.

See Notes 3 and 4 for further discussion of Texas Regulatory Activity.

Ohio Regulatory Activity

The Ohio Electric Restructuring Act of 1999 (Ohio Act) provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. After the end of the MDP, January 1, 2006, customers were scheduled to move to market prices for the supply of electricity.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed rate stabilization plans with the PUCO addressing prices following the end of the MDP. If approved by the PUCO, prices would be established pursuant to CSPCo's and OPCo's plans for the period from January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental, RTO costs and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. The plans include annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo) in 2006, 2007 and 2008 and the opportunity for additional generation-related increases upon PUCO review and approval. Our Ohio Companies Rate Stabilization Plans also provide for the deferral of environmental construction and in-service carrying costs plus PJM RTO administrative fees in 2004 and 2005 for recovery through wires charges in 2006 through 2008. A non-affiliated utility received an order which rejected its request for automatic increases and cost deferrals during the MDP period. The PUCO has indicated in FirstEnergy companies' rate stabilization plans that these plans are specific to a company's requirements and characteristics and the PUCO's order in one case should not be considered a precedent for the plan of another company's rate stabilization plan. Management cannot predict whether CSPCo's and OPCo's plans will be approved as submitted nor can we predict the ultimate impact these proceedings will have on revenues, results of operations and cash flows. See Note 4 for further discussion of Ohio Regulatory Activity.

Oklahoma Regulatory Activity

PSO filed with the Corporation Commission of the State of Oklahoma (OCC) for recovery of a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West electric operating companies of purchased power costs for periods prior to January 1, 2002. The OCC has expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. Intervenor and OCC Staff filings in the case recommended a disallowance of $18 million associated with the allocation of off-system sales margins. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were under the jurisdiction of the OCC because they relate to FERC-approved allocation agreements. As a result, the ALJ ordered that the parties brief the jurisdictional issue. PSO filed its brief on September 1, 2004. Subject to the OCC's decision as to jurisdiction, a hearing date has been set for January 2005. Management believes that fuel costs have been prudently incurred consistent with OCC rules, and that the allocation of off-system sales margins was made pursuant to the FERC-approved allocation agreements. If the OCC determines that a portion of PSO's unrecovered fuel and purchased power costs should not be recovered, there will be, subject to the FERC jurisdictional question, an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

In February 2003, the OCC filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003 and June 2004, PSO filed financial information and supporting testimony in response to the OCC's requirements. PSO's response indicates that its annual revenues are $41 million less than costs. As a result, PSO is seeking OCC approval to increase its base rates by that amount, which is a 3.9% increase over PSO's existing revenues. A decision is not expected until second quarter 2005. Management is unable to predict the ultimate effect of these proceedings on PSO's revenues, results of operations, cash flows and financial condition.

FERC Order on Regional Through and Out Rates

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

AEP and several other utilities in the Combined Footprint have filed a proposal for new rates to become effective December 1, 2004. The AEP East companies received approximately $157 million of T&O rate revenues for the twelve months ended December 31, 2003. At this time, management is unable to predict whether the rate design approved by the FERC will fully compensate the AEP East companies for their lost T&O revenues and whether any resultant increase in rates applicable to AEP's internal load will be recoverable on a timely basis from state retail customers. Unless new replacement rates compensate AEP for its lost revenues and any increase in

AEP East Companies' transmission expenses from these new rates are fully recovered in retail rates on a timely basis, future results of operations, cash flows and financial condition will be adversely affected.

Other Regulatory Activity

There are other significant regulatory risks not included above. See notes 3 and 4 for further discussions of these risks.

RTO Formation

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

Our AEP East companies joined PJM RTO on October 1, 2004. To minimize the credit requirements and operating constraints when joining PJM, the AEP East Companies as well as Wheeling Power Company and Kingsport Power Company, have agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

AEP West companies are members of ERCOT or SPP. In February 2004, the FERC granted RTO status to the SPP, subject to fulfilling specified requirements. In October 2004, the FERC issued an order granting final RTO status to SPP subject to certain filings. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

Litigation

We continue to be involved in various litigation matters as described in the "Significant Factors - Litigation" section of Management's Financial Discussion and Analysis of Results of Operations in our 2003 Annual Report. The 2003 Annual Report should be read in conjunction with this report in order to understand other litigation matters that did not have significant changes in status since the issuance of our 2003 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition. Other matters described in the 2003 Annual Report that did not have significant changes during the first nine months of 2004, that should be read in order to gain a full understanding of our current litigation include: (1) Bank of Montreal Claim, and (2) Potential Uninsured Losses.

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation within "Significant Factors - Environmental Matters."

Enron Bankruptcy

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

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

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

Enron Bankruptcy - Right to use of cushion gas agreements - In connection with the 2001 acquisition of HPL, we also entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 BCF of cushion gas (the 10.5 BCF and 55 BCF described in the preceding paragraph) required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

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

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

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

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

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

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

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In August 2004, the SEC announced it would conduct hearings on this issue. The hearing is scheduled for January 2005.

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUHCA's single region requirement. In its ruling, the appeals court said that the SEC failed to support and explain its conclusions that the interconnection and single region requirements are satisfied.

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

Texas Commercial Energy, LLP Lawsuit

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

Energy Market Investigations

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

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. We responded to the complaint in September 2004. In 2003 we recorded a provision related to these matters. We have engaged in settlement discussions with several agencies and are evaluating whether to conclude settlements in order to put these investigations behind us even though we believe we have meritorious legal positions and defenses. If we elect to settle all matters, the payments could exceed the 2003 provision and could have a material impact on our 2004 earnings and cash flows.

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 AEP executives, members of the Board of Directors and certain investment banking firms. Certain of these actions were dismissed in September 2004. We intend to defend vigorously against the remaining actions. See Note 5 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. Thereafter, two similar actions were filed in the same court against a number of companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. On December 5, 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. We and the other defendants filed a motion to dismiss the complaint which the Court denied in September 2004. We intend to defend vigorously against these claims.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the Clean Air Act for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. No action can be commenced until 60 days after the date of notice.

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

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On August 30, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the reporting of volatile organic compound emissions at the Pirkey Plant.

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

Carbon Dioxide Public Nuisance Claims

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

TEM Litigation

See discussion of TEM litigation within the "Power Generation Facility" section of "Financial Condition - Other" within Management's Financial Discussion and Analysis of Results of Operations.

Environmental Matters

As discussed in our 2003 Annual Report, there are emerging environmental control requirements that we expect will result in substantial capital investments and operational costs. The sources of these future requirements include:

o Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO2), nitrogen oxide (NOx) and mercury emissions from coal-fired power plants,
o New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
o Possible future requirements to reduce carbon dioxide emissions to address concerns about global climatic change.

This discussion updates certain events occurring in 2004. You should also read the "Significant Factors - Environmental Matters" section within Management's Financial Discussion and Analysis of Results of Operations in our 2003 Annual Report for a description of all material environmental matters affecting us, including, but not limited to, (1) the current air quality regulatory framework, (2) estimated air quality environmental investments, (3) Superfund and state remediation, (4) global climate change, and (5) costs for spent nuclear fuel disposal and decommissioning.

Future Reduction Requirements for SO2, NOx and Mercury

In 1997, the Federal EPA adopted new, more stringent national ambient air quality standards for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter non-attainment areas. The Federal EPA finalized designations for ozone non-attainment areas on April 15, 2004. On the same day, the Administrator of the Federal EPA signed a final rule establishing the elements that must be included in state implementation plans (SIPs) to achieve the new standards, and setting deadlines ranging from 2008 to 2015 for achieving compliance with the final standard, based on the severity of non-attainment. All or parts of 474 counties are affected by this new rule, including many urban areas in the Eastern United States.

The Federal EPA identified SO2 and NOx emissions as precursors to the formation of fine particulate matter. NOx emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NOx and SO2 from our generating units are highly probable. In addition, the Federal EPA proposed a set of options for future mercury controls at coal-fired power plants.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% each in emissions of SO2, NOx and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

o The Federal EPA proposed a Clean Air Interstate Rule (CAIR) to reduce SO2 and NOx emissions across the eastern half of the United States (29 states and the District of Columbia) and make progress toward attainment of the new fine particulate matter and ground-level ozone national ambient air quality standards. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
o The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The CAIR would require affected states to include, in their SIPs, a program to reduce NOx and SO2 emissions from coal-fired electric utility units. SO2 and NOx emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO2 emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NOx emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO2 and NOx trading programs were proposed on June 10, 2004.

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

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of maximum achievable control technology (MACT) on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain units have achieved comparable levels of mercury reduction by installing conventional SO2 (scrubbers) and NOx (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite. The proposed standards for sub-bituminous coals potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and we support, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO2 and NOx reduction requirements imposed on the same sources under the CAIR. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, which can be used to comply with the more stringent SO2 and NOx requirements, have also proven effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 tons to 34 tons by 2010 and to 15 tons by 2018. A supplemental proposal including unit-specific allocations and a framework for the emissions budgeting and trading program preferred by the Federal EPA was published in the Federal Register on March 16, 2004. We filed comments on both the initial proposal and the supplemental notice in June 2004.

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

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that we will invest in additional conventional pollution control technology on a major portion of our fleet of coal-fired power plants. Finalization of new requirements for further SO2, NOx and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control. The cost of such facilities could have an adverse effect on future results of operations, cash flows and financial condition unless recovered from customers.

New Source Review Litigation

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

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

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

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

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

Clean Water Act Regulation

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

Spent Nuclear Fuel Disposal

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STP Nuclear Operating Company on behalf of TCC and the other STP owners, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. On January 17, 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continued on the issue of damages owed to I&M by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against I&M and denied damages. In July 2004, I&M appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase. If such cost increases are not recovered on a timely basis in regulated rates, future results of operations and cash flows could be adversely affected.

Nuclear Decommissioning

As discussed in the 2003 Annual Report, decommissioning costs are accrued over the service life of STP. The licenses to operate the two nuclear units at STP expire in 2027 and 2028. TCC had estimated its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year.

In May 2004, an updated decommissioning study was completed for STP. The study estimates TCC's share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. We are currently analyzing the STP study to determine the effect on our asset retirement obligations (ARO) and will make any appropriate adjustments to the ARO liability and related regulatory asset in the fourth quarter 2004. TCC is in the process of selling its ownership interest in STP to a non-affiliate, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Management's Financial Discussion and Analysis of Results of Operations" in the 2003 Annual Report 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.

Other Matters

As discussed in our 2003 Annual Report, there are several "Other Matters" affecting us. The current status of FERC's market power mitigation efforts is described below.

FERC Market Power Mitigation

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. These two screening tests include a "pivotal supplier" test which determines if the market load can be fully served by alternative suppliers and a "market share" test which compares the amount of surplus generation at the time of the applicant's minimum load. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order and directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way.

On August 9, 2004, AEP submitted its Market Power Analysis pursuant to the FERC's Orders on Rehearing. The analysis focused on the three major areas in which AEP serves load and owns generation resources, ECAR, SPP and ERCOT, and the "first tier" control areas for each of those areas.

The pivotal supplier and market share screen analyses that AEP filed demonstrated that AEP does not possess market power in any of the control areas to which it is directly connected (first-tier markets). AEP passed both screening tests in all of its "first tier" markets. In its three "home" control areas, AEP easily passed the pivotal supplier test. AEP, as part of PJM, also passes the market share screen for the PJM destination market. AEP also passed the market share screen for ERCOT. AEP did not pass the market share screen as designed by the FERC for the SPP control area. Consequently, AEP also submitted substantial additional information, including historical purchase and sales data that demonstrates that AEP does not possess market power in any of the "home" destination markets. AEP requested that its existing market-based pricing authorization in all markets be continued based on this analysis. AEP also requested that the FERC rule without instituting a proceeding and without setting a refund date. This case is pending.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

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

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

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

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

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2004

	Utility Operations	Investments Gas Operations	Investments UK Operations (i)	Consolidated
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2003	$286	$5	$(246)	$45
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(108)	(37)	254	109
Fair Value of New Contracts When Entered Into During the Period (b)	-	-	-	-
Net Option Premiums Paid/(Received) (c)	(1)	3	-	2
Change in Fair Value Due to Valuation Methodology Changes (d)	3	-	-	3
Changes in Fair Value of Risk Management Contracts (e)	61	(6)	(10)	45
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	(3)	-	-	(3)
Total MTM Risk Management Contract Net Assets (Liabilities) at September 30, 2004	$238	$(35)	$(2)	201
Net Cash Flow Hedge Contracts (g)				(152)
Net Risk Management Liabilities Held for Sale, included in the totals above (h)				2
Ending Net Risk Management Assets at September 30, 2004				$51

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 and were entered into prior to 2004.
(b) The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts entered into in 2004.
(d) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(f) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed in detail within the following pages.
(h) See Note 7 for discussion of Assets Held for Sale.
(i) During 2004, we began to unwind our risk management contracts within the U.K. as part of our planned divestiture of our UK Operations. We completed the sale of substantially all of our operations and assets in the Investments-UK Operations segment in July 2004.

Detail on MTM Risk Management Contract Net Assets (Liabilities)
As of September 30, 2004

	Utility Operations	Investments Gas Operations	Consolidated
		(in millions)	
Current Assets	$590	$208	$798
Non Current Assets	382	143	525
Total Assets	972	351	1,323
Current Liabilities	(521)	(224)	(745)
Non Current Liabilities	(213)	(162)	(375)
Total Liabilities	(734)	(386)	(1,120)
Total Net Assets (Liabilities), excluding Cash Flow Hedges	$238	$(35)	$203

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of September 30, 2004

	MTM Risk Management Contracts(a)	PLUS: Cash Flow Hedges	Consolidated (b)
		(in millions)	
Current Assets	$798	$12	$810
Non Current Assets	525	2	527
Total MTM Derivative Contract Assets	1,323	14	1,337
Current Liabilities	(745)	(158)	(903)
Non Current Liabilities	(375)	(8)	(383)

Total MTM Derivative Contract Liabilities	(1,120)	(166)	(1,286)
Total MTM Derivative Contract Net Assets (Liabilities)	$203	$(152)	$51

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

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

The table presenting maturity and source of fair value of MTM risk management contract net assets (liabilities) provides two fundamental pieces of information.
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 (Liabilities)
Fair Value of Contracts as of September 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
			(in millions)				
Utility Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$-	$(76)	$2	$8	$-	$-	$(66)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	4	142	19	7	-	-	172
Prices Based on Models and Other Valuation Methods (b)	3	11	13	26	25	54	132
Total	7	77	34	41	25	54	238
Investments - Gas Operations:							
Prices Actively Quoted - Exchange Traded Contracts	13	82	(3)	2	-	-	94
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(55)	(56)	-	-	-	-	(111)
Prices Based on Models and Other Valuation Methods (b)	-	2	(8)	(4)	(3)	(5)	(18)
Total	(42)	28	(11)	(2)	(3)	(5)	(35)
Investments - UK Operations (e):							
Prices Actively Quoted - Exchange Traded Contracts	-	-	-	-	-	-	-
Prices Provided by Other External Sources - OTC Broker Quotes (a)	4	(8)	(1)	-	-	-	(5)
Prices Based on Models and Other Valuation Methods (b)	3	-	-		-	-	3
Total	7	(8)	(1)		-	-	(2)
Consolidated:							
Prices Actively Quoted - Exchange Traded Contracts	13	6	(1)	10	-	-	28
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(47)	78	18	7	-	-	56
Prices Based on Models and Other Valuation Methods (b)	6	13	5	22	22	49	117
Total	$(28)	$97	$22	$39	$22	$49	$201

(a) Prices provided by other external sources - Reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) Modeled - In the absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled.
(c) There is $20 million of mark-to-market value in 2009 and $19 million of mark-to-market value in 2010.
(d) Amounts exclude Cash Flow Hedges.
(e) The majority of these positions will either mature or be settled with the applicable counterparties during the fourth quarter 2004.

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

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of September 30, 2004

Domestic	Transaction Class	Market/Region	Tenor (in months)
Natural Gas	Futures	NYMEX Henry Hub	63
	Physical Forwards	Gulf Coast, Texas	18
	Swaps	Gas East - Northeast, Mid-continent Gulf Coast, Texas	18
	Swaps	Gas West - Rocky Mountains, West Coast	27
	Exchange Option Volatility	NYMEX/Henry Hub	12
Power	Futures	PJM	27
	Physical Forwards	Cinergy	15
	Physical Forwards	First Energy	21
	Physical Forwards	PJM	27
	Physical Forwards	NYPP	27
	Physical Forwards	NEPOOL	15
	Physical Forwards	ERCOT	27
	Physical Forwards	TVA	-
	Physical Forwards	Com Ed	15
	Physical Forwards	Entergy	9
	Physical Forwards	PaloVerde	39
	Physical Forwards	North Path 15, South Path 15	39
	Physical Forwards	Mid Columbia	39
	Peak Power Volatility (Options)	Cinergy	12
	Peak Power Volatility (Options)	PJM	12
Crude Oil	Swaps	West Texas Intermediate	30
Emissions	Credits	SO2	

			51
Coal	Physical Forwards	PRB, NYMEX, CSX	27
International			
Power	Forwards and Options	United Kingdom	42
Coal	Forward Purchases and Sales	United Kingdom	-
	Swaps	Europe	39
Freight	Swaps	Europe	39

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

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

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

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

The tables below provide detail on effective cash flow hedges under SFAS 133 included in our balance sheet. The data in the first table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. This table further indicates what portions of these hedges are expected to be reclassified into net income in the next 12 months. The second table provides the nature of changes from December 31, 2003 to September 30, 2004.

Information on energy merchant activities is presented separately from interest rate and foreign currency risk management activities. In accordance with accounting principles generally accepted in the United States of America, all amounts are presented net of related income taxes.

Cash Flow Hedges included in Accumulated Other Comprehensive Loss On the Balance Sheet as of September 30, 2004

	Accumulated Other Comprehensive Loss After Tax (a)	Portion Expected to be Reclassified to Earnings During the Next 12 Months (b)
	(in millions)	
Power and Gas	$(77)	$(73)
Foreign Currency	-	-
Interest Rate	(25)	(5)

	------	-----
Total	$(102)	$(78)
	======	=====

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2004

	Power and Gas	Foreign Currency	Interest Rate	Consolidated
	-------------	--------	-------------	------------
	(in millions)			
Beginning Balance, December 31, 2003	$(65)	$(20)	$(9)	$(94)
Changes in Fair Value (c)	(73)	-	(21)	(94)
Reclassifications from AOCI to Net Income (d)	61	20	5	86
	-----	-----	-----	------
Ending Balance, September 30, 2004	$(77)	$-	$(25)	$(102)
	=====	=====	=====	======

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

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. Except for one non-investment grade counterparty who has a net exposure of approximately $46 million, we believe that credit exposure with any one counterparty is not material to our financial condition at September 30, 2004. At September 30, 2004, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 19% expressed in terms of net MTM assets and net receivables. The concentration in non-investment grade credit exposure is proportionately higher due to coal exposures related to domestic MTM coal transactions. These exposures were driven by the continued high levels of prices for coal. As of September 30, 2004, the following table approximates our counterparty credit quality and exposure based on netting across commodities and instruments:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties > 10%	Net Exposure of Counterparties > 10%
	(in millions, except number of counterparties)				
Investment Grade	$924	$145	$779	-	$-
Split Rating	30	7	23	3	21
Non-Investment Grade	331	181	150	3	99
No External Ratings:					
Internal Investment Grade	126	-	126	1	16
Internal Non-Investment Grade	69	4	65	2	43
Total	$1,480	$337	$1,143	9	$179

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged, including both contracts designated as cash flow hedges under SFAS 133 and contracts not designated as cash flow hedges. This information is forward-looking and provided on a prospective basis through December 31, 2006. Please note that this table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged," represents the portion of megawatthours of future generation/production for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information

Estimated Next Three Years
As of September 30, 2004

	Remainder 2004	2005	2006
Estimated Plant Output Hedged	92%	88%	88%

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at September 30, 2004, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

VaR Model

Nine Months Ended September 30, 2004 (in millions)				Twelve Months Ended December 31, 2003 (in millions)		
End	High	Average	Low	End	High	Average

Low						
$1	$19	$6	$1	$11	$19	$7
$4						

The 2004 High VaR was due to the wind-down of the London risk management activities. These activities were concluded in March 2004. The 2004 High VaR, excluding London activities, was approximately $8 million.

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

CCRO VaR Metrics

	September 30, 2004	Average for Year-to-Date 2004	High for Year-to-Date 2004	Low for Year-to-Date 2004
		(in millions)		
95% Confidence Level, Ten-Day Holding Period	$5	$21	$73	$5
99% Confidence Level, One-Day Holding Period	$2	$9	$30	$2

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $755 million at September 30, 2004 and $1.013 billion at December 31, 2003. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or consolidated financial position.

We are exposed to risk from changes in the market prices of coal and natural gas used to generate electricity where generation is no longer regulated or where existing fuel clauses are suspended or frozen. The protection afforded by fuel clause recovery mechanisms has either been eliminated by the implementation of customer choice in Ohio (effective January 1, 2001) and in the ERCOT area of Texas (effective January 1, 2002) or frozen by a settlement agreement in West Virginia. To the extent the fuel supply of the generating units in these states is not under fixed-price long-term contracts, we are subject to market price risk. We continue to be protected against market price changes by active fuel clauses in Oklahoma, Arkansas, Louisiana, Kentucky, Virginia and the SPP area of Texas. Fuel clauses are active again in Michigan and Indiana, effective January 1, 2004 and March 1, 2004, respectively. See Note 3 "Rate Matters" for further discussion.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three and Nine Months Ended September 30, 2004 and 2003
(in millions, except per-share amounts)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2004	2003	2004	2003
REVENUES				
Utility Operations	$2,909	$3,099	$7,989	$8,458
Gas Operations	762	707	2,191	2,278
Other	81	135	281	440
TOTAL	3,752	3,941	10,461	11,176
EXPENSES				
Fuel for Electric Generation	781	912	2,209	2,404
Purchased Electricity for Resale	274	207	444	577
Purchased Gas for Resale	725	675	2,011	2,203
Maintenance and Other Operation	843	904	2,679	2,739
Depreciation and Amortization	333	329	972	971
Taxes Other Than Income Taxes	178	179	538	524
TOTAL	3,134	3,206	8,853	9,418
OPERATING INCOME	618	735	1,608	1,758
Other Income (Expense), Net	193	31	286	147
Investment Value Losses	-	70	2	70
INTEREST AND OTHER CHARGES				
Interest	193	216	591	605
Preferred Stock Dividend Requirements of Subsidiaries	2	1	5	7
Minority Interest in Finance Subsidiary	-	-	-	17
TOTAL	195	217	596	629
INCOME BEFORE INCOME TAXES	616	479	1,296	1,206
Income Taxes	204	172	444	429
INCOME BEFORE DISCONTINUED OPERATIONS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES	412	307	852	777
DISCONTINUED OPERATIONS (Net of Tax)	118	(50)	60	(98)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (Net of Tax)				
Accounting for Risk Management Contracts	-	-	-	(49)
Asset Retirement Obligations	-	-	-	242
NET INCOME	$530	$257	$912	$872
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING	396	395	396	382
EARNINGS PER SHARE				
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	$1.04	$0.78	$2.15	$2.03
Discontinued Operations	0.30	(0.13)	0.15	(0.26)
Cumulative Effect of Accounting Changes	-	-	-	0.51

TOTAL EARNINGS PER SHARE (BASIC AND DILUTED)	$1.34	$0.65	$2.30	$2.28
	=======	=======	=======	=======
CASH DIVIDENDS PAID PER SHARE	$0.35	$0.35	$1.05	$1.30
	=======	=======	=======	=======

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in millions)	
CURRENT ASSETS		
Cash and Cash Equivalents	$1,282	$976
Other Cash Deposits	179	206
Accounts Receivable:		
Customers	883	1,155
Accrued Unbilled Revenues	517	596
Miscellaneous	65	83
Allowance for Uncollectible Accounts	(132)	(124)
Total Receivables	1,333	1,710
Fuel, Materials and Supplies	1,074	991
Risk Management Assets	810	766
Margin Deposits	180	119
Other	125	129
TOTAL	4,983	4,897
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	15,829	15,112
Transmission	6,248	6,130
Distribution	10,197	9,902
Other (including gas, coal mining and nuclear fuel)	3,488	3,572
Construction Work in Progress	930	1,305
TOTAL	36,692	36,021
Less: Accumulated Depreciation and Amortization	14,398	14,004
TOTAL-NET	22,294	22,017
OTHER NON-CURRENT ASSETS		
Regulatory Assets	3,480	3,548
Securitized Transition Assets	656	689
Spent Nuclear Fuel and Decommissioning Trusts	1,029	982
Investments in Power and Distribution Projects	190	212
Goodwill	78	78
Long-term Risk Management Assets	527	494
Other	698	733
TOTAL	6,658	6,736
Assets of Discontinued Operations and Held for Sale	887	3,094
TOTAL ASSETS	$34,822	$36,744

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$1,033	$1,337
Short-term Debt	214	326
Long-term Debt Due Within One Year*	1,598	1,779
Risk Management Liabilities	903	631
Accrued Taxes	583	620
Accrued Interest	183	207
Customer Deposits	399	379
Other	719	703
TOTAL	5,632	5,982
NON-CURRENT LIABILITIES		
Long-term Debt*	11,039	12,322
Long-term Risk Management Liabilities	383	335
Deferred Income Taxes	4,520	3,957
Regulatory Liabilities and Deferred Investment Tax Credits	2,290	2,259
Asset Retirement Obligations and Nuclear Decommissioning	696	651
Employee Benefits and Pension Obligations	669	667
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	169	176
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	72	76
Deferred Credits and Other	622	508
TOTAL	20,460	20,951
Liabilities of Discontinued Operations and Held for Sale	386	1,876
TOTAL LIABILITIES	26,478	28,809
Cumulative Preferred Stocks of Subsidiaries not Subject to Mandatory Redemption	61	61
Commitments and Contingencies		
COMMON SHAREHOLDERS' EQUITY		
Common Stock-Par Value $6.50: 2004 / 2003 Shares Authorized. . . . . .600,000,000 / 600,000,000 Shares Issued. . . . . .404,695,982 / 404,016,413 (8,999,992 shares were held in treasury at September 30, 2004 and December 31, 2003)	2,630	2,626
Paid-in Capital	4,197	4,184
Retained Earnings	1,987	1,490
Accumulated Other Comprehensive Income (Loss)	(531)	(426)
TOTAL	8,283	7,874
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$34,822	$36,744

* See Accompanying Schedule

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, 2004 and 2003
(Unaudited)

	2004	2003
	(in millions)	
OPERATING ACTIVITIES		
Net Income	$912	$872
Plus: (Income) Loss from Discontinued Operations	(60)	98
Income from Continuing Operations	852	970
Adjustments for Noncash Items:		
Depreciation and Amortization	972	971
Deferred Income Taxes	88	214
Deferred Investment Tax Credits	(21)	(24)
Cumulative Effect of Accounting Changes	-	(193)
Investment Value Losses	2	70
Amortization of Deferred Property Taxes	93	89
Amortization of Cook Plant Restart Costs	-	30
Mark-to-Market of Risk Management Contracts	89	(124)
Over/Under Fuel Recovery	5	131
Gain on Sales of Assets	(156)	(40)
Change in Other Non-Current Assets	(101)	(51)
Change in Other Non-Current Liabilities	130	(32)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	379	141
Accounts Payable	(313)	(408)
Fuel, Materials and Supplies	(83)	(11)
Customer Deposits	19	102
Taxes Accrued	388	(4)
Interest Accrued	(25)	4
Other Current Assets	(56)	29
Other Current Liabilities	3	(108)
Net Cash Flows From Operating Activities	2,265	1,756
INVESTING ACTIVITIES		
Construction Expenditures	(1,034)	(936)
Change in Other Cash Deposits, Net	27	36
Investment in Discontinued Operations, Net	(59)	(686)
Proceeds from Sales of Assets	1,202	49
Other	(6)	(3)
Net Cash Flows From (Used For) Investing Activities	130	(1,540)
FINANCING ACTIVITIES		
Issuance of Common Stock	13	1,142
Issuance of Long-term Debt	416	4,065
Change in Short-term Debt, Net	(201)	(2,523)
Retirement of Long-term Debt	(1,898)	(1,658)
Retirement of Preferred Stock	(4)	(2)
Retirement of Minority Interest	-	(225)
Dividends Paid on Common Stock	(415)	(479)
Net Cash Flows From (Used For) Financing Activities	(2,089)	320
Net Increase in Cash and Cash Equivalents	306	536
Cash and Cash Equivalents at Beginning of Period	976	1,084
Cash and Cash Equivalents at End of Period	$1,282	$1,620
Net Decrease in Cash and Cash Equivalents from Discontinued Operations	$(4)	$(7)
Cash and Cash Equivalents from Discontinued Operations - Beginning of Period	13	23
Cash and Cash Equivalents from Discontinued Operations - End of Period	$9	$16

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest, net of capitalized amounts, was $576 million and $542 million in 2004 and 2003, respectively. Cash paid (received) for income taxes was $(112) million and $156 million in 2004 and 2003, respectively. Noncash acquisitions under capital leases were $76 million and $9 million in 2004 and 2003, respectively.

In connection with the disposition of AEP Coal in April 2004 the buyer assumed $11 million of non-current liabilities.

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2004 and 2003
(in millions)
(Unaudited)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	348	$2,261	$3,413	$1,999	$(609)	$7,064
Issuance of Common Stock	56	365	812			1,177
Common Stock Dividends				(479)		(479)
Common Stock Expense			(36)			(36)
Other			(5)	1		(4)
TOTAL						7,722
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					25	25
Cash Flow Hedges					(177)	(177)
Securities Available for Sale					1	1
Minimum Pension Liability					15	15
NET INCOME				872		872
TOTAL COMPREHENSIVE INCOME						736
SEPTEMBER 30, 2003	404	$2,626	$4,184	$2,393	$(745)	$8,458
DECEMBER 31, 2003	404	$2,626	$4,184	$1,490	$(426)	$7,874
Issuance of Common Stock	1	4	9			13
Common Stock Dividends				(415)		(415)
Other			4			4
TOTAL						7,476
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					(113)	(113)
Cash Flow Hedges					(8)	(8)
Minimum Pension Liability					16	16
NET INCOME				912		912
TOTAL COMPREHENSIVE INCOME						807
SEPTEMBER 30, 2004	405	$2,630	$4,197	$1,987	$(531)	$8,283

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in millions)	
First Mortgage Bonds	$536	$822
Defeased TCC First Mortgage Bonds (a)	112	118
Installment Purchase Contracts	1,935	2,026
Notes Payable	1,049	1,518
Senior Unsecured Notes	7,640	7,997
Securitization Bonds	698	746
Notes Payable to Trust	113	331
Equity Unit Senior Notes	345	345
Long-term DOE Obligation (b)	228	226
Other Long-term Debt	22	21
Equity Unit Contract Adjustment Payments	12	19
Unamortized Discount (net)	(53)	(68)
TOTAL LONG-TERM DEBT OUTSTANDING	12,637	14,101
Less Portion Due Within One Year	1,598	1,779
TOTAL LONG-TERM PORTION	$11,039	$12,322

(a) On May 7, 2004, we deposited cash and treasury securities of $125 million with a trustee to defease all of TCC's outstanding First Mortgage Bonds. Trust fund assets related to this obligation of $100 million are included in Other Cash Deposits and $22 million are included in Other Non-current Assets in the Consolidated Balance Sheets at September 30, 2004. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(b) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. I&M is the only AEP subsidiary that generated electric power with nuclear fuel prior to that date. Trust fund assets of $261 million and $262 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Consolidated Balance Sheets at September 30, 2004 and December 31, 2003, respectively.

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited interim financial statements should be read in conjunction with the 2003 Annual Report as incorporated in and filed with our 2003 Form 10-K.

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

Other Income (Expense), Net

The following table provides the components of Other Income (Expense), Net as presented on our Consolidated Statements of Operations:

	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(in millions)			
Other Income:				
Interest and Dividend Income	$6	$8	$17	$21
Equity Earnings	5	4	15	6
Nonoperating Revenue	27	34	84	100
Gain on Sale of IPPs (a)	105	-	105	-
Gain on Sale of South Coast (a)	48	-	48	-
Gain on Sale of REPs (Mutual Energy Companies)	-	-	-	39
Other	39	34	124	134
Total Other Income	230	80	393	300
Other Expense:				
Nonoperating Expenses	21	28	67	88
Other	16	21	40	65
Total Other Expense	37	49	107	153
Total Other Income (Expense), Net	$193	$31	$286	$147

(a) See Note 7 "Dispositions, Discontinued Operations and Assets Held for Sale."

Components of Accumulated Other Comprehensive Income (Loss)

The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

Components	September 30, 2004	December 31, 2003
	(in millions)	
Foreign Currency Translation Adjustments	$(3)	$110
Unrealized Losses on Securities Available for Sale	(1)	(1)
Unrealized Losses on Cash Flow Hedges	(102)	(94)

Minimum Pension Liability	(425)	(441)
Total	$(531)	$(426)

At September 30, 2004, we expect to reclassify approximately $78 million of net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) to Net Income during the next twelve months at the time the hedged transactions affect net income. Seventeen months is the maximum period over which an exposure to a variability in future commodity related cash flows is hedged with SFAS 133 designated contracts. Approximately $1 million of the fair value of cash flow hedges at September 30, 2004 are hedging interest rate variability on debt past two years. The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes.

In addition, during the first quarter 2004, we reclassified $23 million from Accumulated Other Comprehensive Income (Loss) related to minimum pension liability to regulatory assets ($35 million) and deferred income taxes ($12 million) as a result of authoritative letters issued by the FERC and the Arkansas and Louisiana commissions.

Accounting for Asset Retirement Obligations

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

	Nuclear Decommissioning	Ash Ponds	U.K. Plants, Wind Mills and Mining Operations	Total
		(in millions)		
Asset Retirement Obligation Liability at January 1, 2004 Including Held for Sale	$770.9	$75.4	$53.1	$899.4
Accretion Expense	41.9	4.5	2.4	48.8
Foreign Currency Translation	-	-	0.6	0.6
Liabilities Incurred	-	-	17.7	17.7
Liabilities Settled	-	(0.4)	(56.9)	(57.3)
Revisions in Cash Flow Estimates	-	-	15.0	15.0
Asset Retirement Obligation Liability at September 30, 2004 including Held for Sale	812.8	79.5	31.9	924.2
Less Asset Retirement Obligation Liability Held for Sale: South Texas Project (a)	(231.2)	-	-	(231.2)
Asset Retirement Obligation Liability at September 30, 2004	$581.6	$79.5	$31.9	$693.0

(a) We have signed an agreement to sell TCC's share of South Texas Project (see Note 7 for additional information).

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

At September 30, 2004 and December 31, 2003, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $902 million and $845 million, respectively, of which $768 million and $720 million relating to the Cook Plant was recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Consolidated Balance Sheets. The fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities for the South Texas Project totaling $134 million and $125 million as of September 30, 2004 and December 31, 2003, respectively, was classified as Assets of Discontinued Operations and Held for Sale in our Consolidated Balance Sheets.

Reclassifications

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

2. NEW ACCOUNTING PRONOUNCEMENTS

FASB Interpretation Number (FIN) 46 (revised December 2003)"Consolidation of Variable Interest Entities" FIN 46R
We implemented FIN 46R, "Consolidation of Variable Interest Entities," effective March 31, 2004 with no material impact to our financial statements. FIN 46R is a revision to FIN 46 which interprets the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties.

FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

We implemented FASB Staff Position (FSP) FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," effective April 1, 2004, retroactive to January 1, 2004. The new disclosure standard provides authoritative guidance on the accounting for any effects of the Medicare prescription drug subsidy under the Act. It replaces the earlier FSP FAS 106-1, under which we previously elected to defer accounting for any effects of the Act until the FASB issued authoritative guidance on the accounting for the Medicare subsidy.

Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106's 10 percent corridor. The Medicare subsidy reduced our FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million. The tax-free subsidy reduced the 2004 year-to-date net periodic postretirement benefit cost, after adjustment to capitalization of employee benefits costs as a cost of construction projects, by a total of $20 million.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes. The FASB is currently working on several projects including discontinued operations, business combinations, liabilities and equity, revenue recognition, accounting for share-based compensation, pension plans, asset retirement obligations, earnings per share calculations, fair value measurements, accounting changes and related tax impacts. We also expect to see more FASB projects as a result of their desire to converge International Accounting Standards with those generally accepted in the United States of America. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

3. RATE MATTERS

As discussed in our 2003 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and at several state commissions. The Rate Matters note within our 2003 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material rate matters still pending, without significant changes since year-end. The following sections discuss current activities.

TNC Fuel Reconciliation

In 2002, TNC filed with the PUCT to reconcile fuel costs, requesting to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the True-up Proceeding. This reconciliation for the period from July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory.

In March 2003, the ALJ in this proceeding filed a Proposal for Decision (PFD) with a recommendation that TNC's under-recovered retail fuel balance be reduced. In March 2003, TNC established a provision for probable disallowance of $13 million based on the recommendations in the PFD. In May 2003, the PUCT reversed the ALJ on certain matters and remanded TNC's final fuel reconciliation to the ALJ to consider two issues: (1) the sharing of off-system sales margins from AEP's trading activities with customers for five years per the PUCT's interpretation of the Texas AEP/CSW merger settlement and (2) the inclusion of January 2002 fuel factor revenues and associated costs in the determination of the under-recovery. The PUCT proposed that the sharing of off-system sales margins for periods beyond the termination of the fuel factor should be recognized in the final fuel reconciliation proceeding. This would result in the sharing of margins for an additional three and one-half years after the end of the Texas ERCOT fuel factor. While management believes that the Texas merger settlement only provided for sharing of margins during the period fuel and generation costs were regulated by the PUCT, an additional provision of $10 million was recorded in December 2003.

In December 2003, the ALJ issued a PFD in the remand phase of the TNC fuel reconciliation recommending additional disallowances for the two remand issues. TNC filed responses to the PFD, and the PUCT announced a final ruling in the fuel reconciliation proceeding in January 2004 accepting the PFD. TNC received a written order in March 2004 and increased its provision by $1.5 million. In March 2004, various parties, including TNC, requested a rehearing of the PUCT's ruling. In May 2004, the PUCT reversed its position on the inclusion of MTM amounts in the allocation of system sales margins and remanded the case to the ALJ. As a result, TNC recorded an additional provision of $12 million in the second quarter of 2004 resulting in a provision for an over-recovery balance of approximately $7 million.

On July 2, 2004, the parties to the MTM remand proceeding filed a "Stipulation of Fact" in which all parties agreed to the quantification of the remanded issue. With the amounts included in the "Stipulation of Fact," the over-recovery balance would be $4 million. On October 13, 2004 the PUCT approved an order which included the amounts contained in the "Stipulation of Fact." The PUCT issued an order in the fuel reconciliation which reflected the "Stipulation of Fact" in October 2004. TNC will seek rehearing of the PUCT's order regarding issues other than the issue covered by the stipulation. TNC may appeal to the Texas District Court the PUCT's decision once all motions for rehearing have been adjudicated. Management expects to adjust its provision to an over-recovery balance of $4 million when it receives a final order in the fourth quarter 2004. Although management believes it has adequately provided for probable disallowances, a final order from the PUCT disallowing amounts in excess of the established provision could have a material adverse impact on future results of operations and cash flows.

In February 2002, TNC received a final order from the PUCT in a previous fuel reconciliation covering the period July 1997 through 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 was appealed by certain cities (the Cities) to the Third Court of Appeals. The Third Court of Appeals issued a ruling on September 23, 2004 upholding the District Court and the PUCT's final order. It is unknown at this time if the Cities will appeal to the Texas Supreme Court or if the court will hear the issue if they do.

TCC Fuel Reconciliation

In 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the True-up Proceeding. This reconciliation covers the period from July 1998 through December 2001.

Based on the PUCT ruling in the TNC proceeding related to similar issues, TCC established a provision for probable adverse rulings of $81 million during 2003. On February 3, 2004, the ALJ issued a PFD in the TCC case recommending that the PUCT disallow $140 million in eligible fuel costs including some new items not considered in the TNC case, and other items considered but not disallowed in the TNC ruling. Based on an analysis of the ALJ's recommendations and the initial final order in the TNC fuel reconciliation, TCC established an additional provision of $13 million during the first quarter of 2004. In May 2004, the PUCT accepted most of the ALJ's recommendations in the TCC case, however, the PUCT rejected the ALJ's recommendation to impute capacity to certain energy-only purchased power contracts and remanded the issue to the ALJ to determine if any energy-only purchased power contracts during the reconciliation period include a capacity component that is not recoverable in fuel revenues. In testimony filed in the remand proceeding, TCC has asserted that its energy-only purchased power contracts do not include any capacity component. Intervenors, including the Office of Public Utility Counsel, have filed testimony recommending that $15 million to $30 million of TCC's purchased power costs reflect capacity costs which are not recoverable in the fuel reconciliations. Hearings were held in October 2004 on this remand issue. As a result of the PUCT's acceptance of most of the ALJ's recommendations in TCC's case and the PUCT's remand decision in the TNC case regarding the inclusion of MTM amounts in the allocation of AEP's net system sales margins, TCC increased its provision by $47 million in the second quarter of 2004. The over-recovery balance and the provisions for probable disallowances totaled $210 million including interest at September 30, 2004.

At this time, management is unable to predict the outcome of this proceeding. Management believes it has provided for all probable to-date disallowances pending receipt of a final order. A final order has not yet been issued in TCC's final fuel reconciliation. We will continue to challenge adverse decisions vigorously, including appeals if necessary. An order from the PUCT, disallowing amounts in excess of the established provision, could have a material adverse effect on future results of operations and cash flows. Additional information regarding the True-up Proceeding for TCC can be found in Note 4 "Customer Choice and Industry Restructuring."

SWEPCo Texas Fuel Reconciliation

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in the SPP. This reconciliation covers the period from January 2000 through December 2002. During the reconciliation period, SWEPCo incurred $435 million of Texas retail eligible fuel expense. In November 2003, intervenors and the PUCT Staff recommended fuel cost disallowances of more than $30 million. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation. The settlement provides for a disallowance in fuel costs of $8 million which was recorded in December 2003. In April 2004 the PUCT approved the settlement.

Virginia Fuel Factor Filing

On October 29, 2004 APCo filed with the Virginia SCC to increase its fuel factor effective January 1, 2005. The requested factor is estimated to increase revenues by approximately $19 million on an annual basis. This increase reflects a continuing rise in the projected cost of coal in 2005. This fuel factor adjustment will increase cash flows without impacting results of operations as any over-recovery or under-recovery of fuel cost would be deferred as a regulatory liability or a regulatory asset.

TCC Rate Case

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

In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCC's requested $67 million rate increase. The recommendations ranged from a decrease in existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. Hearings were held in March 2004. In May 2004, TCC agreed to a non-unanimous settlement on cost of capital including capital structure and return on equity with all but two parties in the proceeding. TCC agreed that the return on equity should be established at 10.125% based upon a capital structure with 40% equity resulting in a weighted cost of capital of 7.475%. The settlement and other agreed adjustments reduced TCC's rate request from $67 million to $41 million. The ALJs that heard the case issued their recommendations on July 2, 2004, including a recommendation to approve the cost of capital settlement. The ALJs recommended that an issue related to the allocation of consolidated tax savings to the transmission and distribution utility be remanded for additional evidence. On July 15, 2004, the PUCT remanded this issue to the ALJs. On August 19, 2004, in a separate ruling the PUCT remanded six other issues to the ALJs requesting revisions to clarify and further support the recommendations in the PFD. In addition, the PUCT ordered TCC to calculate its revenue requirements based upon the recommendations of the ALJs. On July 21, 2004, TCC filed its revenue requirements based upon the recommendations of the ALJs. According to TCC's calculations, the ALJs' recommendations reduce TCC's existing rates by a range of somewhere between $33 million and $43 million depending on the final resolution of the amount of consolidated tax savings. Hearings were held on the consolidated tax savings remand issue in September. The PUCT is expected to issue its decision by the end of 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates, revenues, results of operations, cash flows and financial condition.

On September 2, 2004, a group of intervenors, with subsequent support of the PUCT Staff, filed a request that a $30 million temporary, or interim, rate reduction be ordered subject to refund or surcharge. On September 24, 2004 the PUCT issued an order denying the motion for reduced temporary rates.

Louisiana Compliance Filing

In October 2002, SWEPCo filed with the Louisiana Public Service Commission (LPSC) detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid-2005. In April 2004, SWEPCo filed updated financial information with a test year ending December 31, 2003 as required by the LPSC. Both filings indicated that SWEPCo's current rates should not be reduced. Subsequently, direct testimony was filed on behalf of the LPSC recommending a $15.4 million reduction in SWEPCo's Louisiana jurisdictional base rates. SWEPCo's rebuttal testimony is due December 15, 2004. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ordered in the future, it would adversely impact results of operations and cash flows.

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 overcharged them for fuel costs since 1975. The LPSC consolidated the customer complaint and audit. A status conference is scheduled for December 16, 2004 to schedule a hearing date. Although management believes that SWEPCo's fuel costs were proper and fuel costs incurred prior to 1999 were approved by the LPSC, we are unable to predict the outcome of these proceedings. If the actions of the LPSC or the Court result in a material disallowance of SWEPCo's fuel recoveries, it would have an adverse impact on results of operations and cash flows. The LPSC Staff consultant made recommendations to reduce recoverable fuel expense from SWEPCo's Louisiana retail customers. The consultant recommended that SWEPCo be required to refund $3.9 million (through December 2002) stating the amount should be recovered through base rates versus the fuel factor. An additional amount of $1.4 million for the period of January 2003 through September 2004 would also be required to be refunded. In addition, the LPSC Staff contends that SWEPCo's Pirkey Power Plant experienced poor performance during the years 1999, 2001 and 2002 and that the incremental cost of replacement power should be refunded. The consultant did not provide an amount associated with this recommendation, but management believes that the amount could be material. If the LPSC adopts any of the consultant's recommendations, it would adversely impact results of operations and cash flows.

PSO Fuel and Purchased Power

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West electric operating companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the OCC seeking to recover these reallocated costs over a period of 18 months. In August 2003, the OCC Staff filed testimony recommending PSO be granted recovery of $42.4 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed testimony in February 2004. An intervenor and the OCC Staff filed testimony in April 2004. The intervenor suggested that $8.8 million related to the 2002 reallocation not be recovered from customers. The Attorney General of Oklahoma also filed a statement of position, indicating allocated off-system sales margins between and among AEP operating companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and if corrected could more than offset the $44 million 2002 reallocation under-recovery. The intervenor and the OCC Staff also believed off-system sales margins were allocated incorrectly and that a reallocation by the intervenors of such margins would reduce PSO's recoverable fuel by an additional $6.8 million for 2000 and $10.7 million for 2001, while under the OCC Staff method, the reduction for 2001 would be $8.8 million. The intervenor and the OCC Staff also recommend recalculation of fuel for years subsequent to 2001 using the same revised methods. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were under the jurisdiction of the OCC because they relate to FERC-approved allocation agreements. As a result, the ALJ ordered that the parties brief the jurisdictional issue. PSO filed its brief on September 1, 2004. Subject to the OCC's decision as to jurisdiction, a hearing date has been set for January 2005. Management believes that fuel costs have been prudently incurred consistent with OCC rules, and that the allocation of off-system sales margins was made pursuant to the FERC-approved allocation agreements. If the OCC determines that a portion of PSO's unrecovered fuel and purchased power costs should not be recovered, there will be, subject to the FERC jurisdictional question, an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

PSO Rate Review

In February 2003, the OCC filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003 and June 2004, PSO filed financial information and supporting testimony in response to the OCC's requirements. PSO's response indicates that its annual revenues are $41 million less than costs. As a result, PSO is seeking OCC approval to increase its base rates by that amount, which is a 3.9% increase over PSO's existing revenues. Hearings are scheduled to begin in February 2005 to address cost of service, fuel procurement and resource planning issues.

On August 12, 2004, PSO filed a motion to amend the schedule to consider new service quality and reliability requirements which took effect on July 1, 2004. On August 30, 2004, the OCC approved a revised schedule. On October 4, 2004, PSO filed supplemental information requesting consideration of approximately $55 million of additional annual operations and maintenance expenses and annual capital costs to enhance system reliability. On November 4, 2004, PSO filed a plan with the OCC seeking interim rate relief to fund a portion of the costs to meet the new state service quality and reliability requirements pending the outcome of the current case. In the filing, PSO seeks interim approval to collect incremental distribution tree trimming costs of approximately $29 million from its customers. The OCC Staff and intervenors are scheduled to file testimony regarding their recommendations on revenue requirement, fuel procurement, resource planning and vegetation management in December 2004. Rebuttal testimony is to be filed in January 2005 with hearings beginning in February 2005. A decision is not expected until second quarter 2005. Management is unable to predict the ultimate effect of these proceedings on PSO's revenues, results of operations, cash flows and financial condition.

RTO Formation/Integration

Based on FERC approvals in response to non-affiliated companies' requests to defer RTO formation costs, the AEP East companies deferred costs incurred under FERC orders to originally form a new RTO (the Alliance RTO) or subsequently to join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both Alliance RTO formation costs and PJM integration costs including the deferral of a carrying charge thereon. The AEP East companies have deferred approximately $35 million of RTO formation and integration costs and related carrying charges through September 30, 2004. As a result of the subsequent delay in the integration of AEP's East transmission system into PJM, the FERC declined to rule, in its July 2003 order, on our request to transfer the deferrals to regulatory assets, and to maintain such deferrals until such time as the costs can be recovered from all users of AEP's East transmission system.

In its July 2003 order, the FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the open access transmission tariff (OATT) to be charged by PJM. Management believes that the FERC will grant permission for prudently incurred deferred RTO formation/integration costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of the AEP East companies' portion of the OATT as these companies file rate cases. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo and OPCo until 2006 and I&M until 2005.

In August 2004, we filed an application with the FERC dividing the RTO formation/integration costs between PJM-billed integration costs including related carrying charges, and all other RTO formation/integration costs. We intend to file with the FERC to request that deferred PJM-billed integration costs be recovered. The AEP East companies will be responsible for paying the amount allocated by the FERC to the AEP zone since it will be attributable to their internal load. In our August 2004 application, we requested permission to amortize approximately one-half of the deferred costs within the AEP zone over fifteen years beginning on January 1, 2005. We also requested to begin amortizing the deferred PJM-billed integration costs on January 1, 2005, but we did not propose an amortization period in the application.

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

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

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

In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. The order was based on PURPA 205(a), which allows the FERC to exempt electric utilities from state law or regulation in certain circumstances. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the exceptions under PURPA 205(a) apply. The FERC ALJ affirmed the FERC's preliminary findings in March 2004. The FERC issued an order related to this matter in June 2004 affirming its preliminary findings. In September 2004, Virginia filed an offer of settlement with the FERC in which they agreed to cease all attempts to obtain judicial relief from the June 2004 order on the condition that the FERC vacate the order. The FERC has not ruled on Virginia's settlement offer.

The AEP East companies integrated into PJM on October 1, 2004. The AEP East state regulatory Commissions have approved our integration with PJM and FERC has ordered us to defer our RTO formation/integration costs. Such costs will be recovered on an amortization basis through an OATT tariff charged to users of the system. The AEP East companies will also be charged by PJM for use of the system. AEP plans to seek recovery for the portion of the deferred RTO costs that are billed to the AEP East companies by PJM in future rate proceedings. The AEP East companies will expense their portion of the costs billed by PJM. Management is unable to predict whether the FERC will grant a long enough amortization period to allow for the opportunity for recovery of the non-PJM billed deferred RTO formation/integration costs in the AEP East state retail jurisdictions, and whether the state regulatory Commissions will ultimately permit recovery of such costs billed to the AEP East companies by PJM. If the FERC ultimately decides not to approve an amortization period that would provide us with the opportunity to include such costs in future retail rate filings or the FERC or the state commissions deny recovery of our share of these costs, future results of operations and cash flows could be adversely affected.

FERC Order on Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the Midwest Independent System Operator (ISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and expanded PJM regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs' revenue distribution protocols. The order provided that affected transmission owners could file to offset the elimination of these revenues by increasing rates or utilizing a transitional rate mechanism to recover lost revenues that result from the elimination of the T&O rates. The FERC also found that the T&O rates of certain other companies that were then planning to join either PJM or Midwest Independent System Operator (MISO) ("Former Alliance RTO Participants"), including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the Combined Footprint. The FERC also initiated an investigation and hearing in regard to these rates.

In November 2003, the FERC issued an order finding that the T&O rates of the Former Alliance RTO Participants should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and Former Alliance RTO Participants, including AEP, to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004. The FERC was expected to implement a new rate design after the two-year period. As required by the FERC, AEP filed compliance tariff changes in January 2004 to eliminate the T&O charges within the Combined Footprint. Various parties raised issues with the SECA rate orders and the FERC implemented settlement procedures before an ALJ.

In April 2004, the FERC approved a settlement that delayed elimination of T&O rates until December 1, 2004 and provided principles and procedures for development of a new rate design for the Combined Footprint, to be effective on December 1, 2004. The settlement also provides that if the process did not result in the implementation of a new rate design on December 1, then the SECA rates will be implemented and will remain in effect until a new rate is implemented by the FERC. If implemented, the SECA rate would not be effective beyond March 31, 2006.

On September 16, 2004 the FERC Chief ALJ, acting as Settlement Judge, reported to the FERC that attempts to settle the issues had failed, and at least two competing long-term rate design proposals for the Combined Footprint were filed on October 1, 2004. AEP and several other utilities in the Combined Footprint have filed a proposal for new rates to become effective December 1, 2004.

The AEP East companies received approximately $157 million of T&O rate revenues for the twelve months ended December 31, 2003. At this time, management is unable to predict whether the rate design approved by the FERC will fully compensate the AEP East companies for their lost T&O revenues and whether any resultant increase in rates applicable to AEP's internal load will be recoverable on a timely basis from state retail customers. Unless new replacement rates compensate AEP for its lost revenues and any increase in AEP East Companies' transmission expenses from these new rates are fully recovered in retail rates on a timely basis, future results of operations, cash flows and financial condition will be adversely affected.

Indiana Fuel Order

On August 27, 2003, the IURC ordered that certain parties must negotiate the appropriate action on I&M's fuel cost recovery beginning March 1, 2004, following the February 2004 expiration of a fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant outage issues). The fixed fuel adjustment charge capped fuel recoveries. In an agreement in connection with AEP's planned corporate separation, I&M agreed, contingent on AEP implementing the corporate separation, to a fixed fuel adjustment charge beginning March 2004 and continuing through December 2007. Although we have not corporately separated, certain parties believe the fixed fuel adjustment charge should continue beyond February 2004. Negotiations with the parties to resolve this issue are ongoing. The IURC ordered that the fixed fuel adjustment charge remain in place, on an interim basis, in March and April 2004.

In April 2004, the IURC issued an order that extended the interim fuel factor for May through September 2004, subject to true-up to actual fuel costs following the resolution of the issue regarding the corporate separation agreement. The IURC also issued an order that reopened the corporate separation docket to investigate issues related to the corporate separation agreement. In July 2004, we filed for approval of a fuel factor for the period October 2004 through March 2005. On September 22, 2004, the IURC issued an order extending the interim fuel factor for October 2004 through March 2005, subject to true-up upon resolution of the corporation separation issues. At September 30, 2004, I&M has over-recovered its fuel costs and has recorded a regulatory liability to refund such over-recovery. However, if I&M's position should shift to a net under-recovery, the fixed fuel adjustment factor, capping the fuel revenues, could adversely affect results of operations and cash flows if recovery is denied by the IURC.

Michigan 2004 Fuel Recovery Plan

A 1999 Michigan Public Service Commission (MPSC) order approved a Settlement Agreement regarding the extended outage of the Cook Plant and fixed I&M's Power Supply Cost Recovery (PSCR) factors for the St. Joseph and Three Rivers rate areas through December 2003. As required, I&M filed its 2004 PSCR Plan with the MPSC on September 30, 2003 seeking new fuel and power supply recovery factors to be effective in 2004. A public hearing was held on March 10, 2004. On June 4, 2004, the ALJ recommended that SO2 and NOx net credits be excluded from the fuel recovery mechanism. I&M filed its exceptions in June 2004. A MPSC order is expected during the fourth quarter of 2004. As allowed by Michigan law, the proposed factors were effective on January 1, 2004, subject to review by the MPSC and possible adjustment. When SO2 and NOx are a net cost exclusion from the fuel cost recovery mechanism, it will adversely affect future results of operations and cash flows. On September 30, 2004, I&M filed its 2005 PSCR Plan.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

As discussed in our 2003 Annual Report, we are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in our 2003 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end.

The following paragraphs discuss significant current events related to customer choice and industry restructuring.

OHIO RESTRUCTURING

The Ohio Electric Restructuring Act of 1999 (Ohio Act) provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005. The Public Utilities Commission of Ohio (PUCO) may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utility's certified territory or that there is a twenty percent switching rate of the incumbent utility's load by customer class. Following the MDP, retail customers will receive cost-based regulated distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates.

On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rules provide for a Market Based Standard Service Offer (MBSSO) which would be a variable rate based on a transparent forward market, daily market, and/or hourly market prices. The rules also require a fixed-rate Competitive Bidding Process (CBP) for residential and small nonresidential customers and permits a fixed-rate CBP for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the MBSSO and the CBP. Customers who make no choice will be served pursuant to the CBP. The rules also required that electric distribution utilities file an application for MBSSO and CBP by July 1, 2004. CSPCo and OPCo were recently granted a waiver from making the required MBSSO/CBP filing, pending the outcome of a rate stabilization plan they filed with the PUCO in February 2004.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed rate stabilization plans with the PUCO addressing prices following the end of the MDP. If approved by the PUCO, prices would be established pursuant to CSPCo's and OPCo's plans for the period from January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. The plans include annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo) in 2006, 2007 and 2008 and the opportunity for additional generation-related increases upon PUCO review and approval. For residential customers, however, if the temporary 5% generation rate discount provided by the Ohio Act were eliminated prior to December 31, 2005 as permitted by the Ohio Act, the fixed increases would be adjusted downward to reflect the effect of such elimination. Additionally, the plan includes the opportunity to annually request an additional increase averaging 4% per year for both companies in the event costs run beyond the level currently anticipated. The plans would maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level effective on December 31, 2005. Such rates could be adjusted for specified reasons. Transmission charges could also be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion, and ancillary services. The plans also provide for continued amortization and recovery of stranded transition generation-related regulatory assets and for the deferral as regulatory assets in 2004 and 2005 of RTO costs and carrying charges on governmentally mandated, mainly environmental, capital expenditures. Hearings were held in June 2004 on the Companies' proposed rate stabilization plans. Briefs were submitted in July. The filings are pending before the PUCO.

The PUCO, in a recent order involving a non-affiliated company's rate stabilization plan, noted its reluctance to authorize automatic increases in any portion of rates and required a PUCO determination in the future prior to adjusting a rate component, instead of the automatic increases to the rate component which had been proposed. It also held that deferral during the MDP of certain expenses at issue in the case, for recovery after the MDP, would violate the rate cap under the Ohio Act. The PUCO has been asked in that case to reconsider these holdings and that request currently is pending. OPCo's and CSPCo's rate plans and the record in its cases are distinct from the rate plan and record considered by the PUCO in its recent order. In that regard, the PUCO has indicated in FirstEnergy companies' rate stabilization plans that these plans are specific to a company's requirements and characteristics and the PUCO's order in one case should not be considered precedent for another company's rate stabilization plan.

Management cannot predict whether CSPCo's and OPCo's plans will be approved as submitted nor can we predict the ultimate impact these proceedings will have on revenues, results of operations and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, we are deferring customer choice implementation costs and related carrying costs 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. Through September 30, 2004, we incurred $75 million of such costs, and accordingly, we deferred $35 million for probable future recovery in distribution rates. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. If the rate stabilization plan is approved as filed, it would defer recovery of these amounts until the next distribution rate filing. Management believes that its deferred customer choice implementation costs were prudently incurred and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING

Texas Legislation enacted in 1999 provides the framework and timetable to allow retail electricity competition for all Texas customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007. TCC and TNC operate in ERCOT while SWEPCo and a small portion of TNC's business is in SPP.

The Texas Legislation, among other things:
o provides for the recovery of stranded generation plant costs, generation-related regulatory assets and other generation true-up amounts through securitization and non-bypassable wires charges,
o requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility,
o provides for an earnings test for each of the years 1999 through 2001 and,
o provides for a stranded cost True-up Proceeding after January 10, 2004.

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

TEXAS TRUE-UP PROCEEDINGS

The True-up Proceedings will determine the amount and recovery of:
o stranded generation plant costs and generation-related regulatory assets including any unrefunded accumulated excess earnings (stranded generation costs),
o carrying charges on true-up amounts from January 1, 2002 (the commencement date of retail competition),
o a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up),
o final approved deferred fuel balance,
o excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
o and other true-up items.

The PUCT adopted a rule in 2003 regarding the timing of the True-up Proceedings scheduling TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later. TNC filed its true-up request in June 2004 and updated the filing in October 2004. Due to regulatory and contractual delays in the sale of its generating assets, TCC has not filed its true-up request.

True-up Net Regulatory Asset (Liability) Recorded at September 30, 2004:

	TCC	TNC
	(in millions)	
Components of Net Stranded Generation Costs:		
Stranded Generation Plant Costs	$1,079	$-
Unsecuritized Transition Generation Regulatory Asset	249	-
Unrefunded Excess Earnings	(15)	-
Other	(56)	-
Net Stranded Generation Costs	1,257	-
Components of Other Recoverable True-up Amounts:		
Wholesale Capacity Auction True-up	480	-
Retail Clawback (a)	(60)	(14)
Deferred Over-recovered Fuel Balance	(210)	(7)
Other Recoverable True-up Amounts	210	(21)
Total Recorded Net True-up Regulatory Asset (Liability)	$1,467	$(21)

(a) Only half of these amounts are actually recorded as regulatory liabilities, as the other half are the responsibility of the unaffiliated company that owns the affiliated price-to-beat REP.

See discussion below of the above amounts.

Net Stranded Generation Costs

The Texas Restructuring Legislation required utilities with stranded generation plant costs to use market-based methods to value certain generation assets for determining stranded generation plant costs. TCC is the only AEP subsidiary that has stranded generation plant costs under the Texas Legislation. TCC elected to use the sale of assets method to determine the market value of TCC's generation assets for determining stranded generation plant costs. For purposes of the True-up Proceeding, the amount of stranded generation plant costs under this market valuation methodology will be the amount by which the book value of TCC's generation assets exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. Based on the prices established by the generation asset sales, discussed below, TCC recorded a net regulatory asset of $1.1 billion for its stranded generation plant costs from the sale of TCC's generation assets as shown in the table above, before accrual of any applicable carrying charges discussed below.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCC's generation capacity in Texas. We received bids for all of TCC's generation plants. In January 2004, TCC agreed to sell its 7.81% ownership interest in the Oklaunion Power Station to an unaffiliated third party for approximately $43 million. In March 2004, TCC agreed to sell its 25.2% ownership interest in STP for approximately $333 million and its other coal, gas and hydro plants for approximately $430 million to unaffiliated entities. Each sale is subject to specified price adjustments. TCC sent right of first refusal notices to the co-owners of Oklaunion and STP. TCC filed for FERC approval of the sales of Oklaunion, STP and the fossil and hydro plants. We received a notice from co-owners of Oklaunion and STP exercising their right of first refusal; therefore, SEC approval will be required. The original unaffiliated third party purchaser of Oklaunion has petitioned for a court order declaring its contract valid and the co-owners' rights of first refusal void. The sale of STP will also require approval from the Nuclear Regulatory Commission. On July 1, 2004, TCC completed the sale of the other coal, gas and hydro plants for approximately $425 million, net of adjustments. The closings of the sales of STP and Oklaunion plants are expected to occur in the first half of 2005, subject to clarification of the rights of first refusal and the necessary regulatory approvals. In addition, there could be delays in resolving litigation with a third party affecting Oklaunion. In order to sell these assets, TCC defeased all of its remaining outstanding first mortgage bonds in May 2004. In December 2003, we recognized as a regulatory asset an estimated impairment from the sale of TCC's generation assets. TCC is considering seeking a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closings of the sales of all the generation assets.

In addition to its $1.1 billion of stranded generation plant costs, the Texas legislation permits TCC to recover its remaining unsecuritized net transition generation regulatory assets of $249 million less a regulatory liability for the unrefunded excess earnings of $15 million, discussed below. With other adjustments, TCC's recorded net stranded generation costs total $1.3 billion.

Unrefunded Excess Earnings

The Texas Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined by the PUCT for this three-year period were $3 million for SWEPCo, $47 million for TCC and $19 million for TNC. TCC, TNC and SWEPCo challenged the PUCT's treatment of fuel-related deferred income taxes and appealed the PUCT's final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. After appealing the District Court ruling upholding the PUCT decision, the Third Court of Appeals reversed the PUCT order and the District Court's judgment. The District Court remanded to the PUCT an appeal of the same issue from the PUCT's 2001 order upon agreement of the parties after issuance of the Third Court of Appeals decision. On September 14, 2004, the parties to the PUCT remand reached an agreement, which changed the method for calculating excess earnings, which, in turn, revised the calculation for 2000 and 2001 consistent with the ruling of the court. Revised excess earnings for the three-year period were approximately $3 million for SWEPCo, $42 million for TCC and $15 million for TNC. The PUCT issued a final order approving the agreement in October 2004. Since an expense and regulatory liability had been accrued in prior years in compliance with the PUCT orders, the companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Court's decision and credited amortization expense during the third quarter of 2003. Under the Texas legislation since TNC and SWEPCo do not have stranded generation plant cost, excess earnings have been applied to reduce T&D capital expenditures.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order had no additional effect on reported net income but reduces cash flows over the refund period. The remaining $15 million to be refunded is recorded as a regulatory liability at September 30, 2004 and can be included as a reduction to TCC's stranded generation plant costs. Management believes that TCC has stranded costs and that it was, therefore, inconsistent with the Texas restructuring legislation for the PUCT to order a refund prior to TCC's True-up Proceeding. TCC appealed the PUCT's premature refund of excess earnings to the Travis County District Court. That court affirmed the PUCT's decision and further ordered that the refunds be provided to ultimate customers. TCC has appealed the decision to the Third Court of Appeals.

Carrying Charges on Recoverable Stranded Costs

In December 2001, the PUCT issued a rule concerning stranded cost true-up proceedings stating, among other things, that carrying costs on stranded costs would begin to accrue on the date that the PUCT issued its final order in the True-up Proceeding. TCC and one other Texas electric utility company filed a direct appeal of the rule to the Texas Third Court of Appeals contending that carrying costs should commence on January 1, 2002, the day that retail customer choice began in ERCOT.

The Third Court of Appeals ruled against the utilities, who then appealed to the Texas Supreme Court. On June 18, 2004, the Texas Supreme Court reversed the decision of the Third Court of Appeals determining that a carrying cost should be accrued beginning January 1, 2002 and remanded the proceeding to the PUCT for further consideration. The Supreme Court determined that utilities with stranded costs are not permitted to over-recover stranded costs and the PUCT should address whether any portion of the 2002 and 2003 wholesale capacity auction true-up regulatory asset includes a recovery of stranded costs or carrying costs on stranded costs. A motion for rehearing with the Supreme Court was denied and the ruling is final.

The PUCT in September 2004 considered the Supreme Court's decision in true-up hearings held for another utility, CenterPoint Energy, Inc. (CenterPoint). In that case while the PUCT has indicated preliminary positions regarding the methodology to calculate recoverable carrying costs, uncertainties exist as to the ultimate methodology that will be adopted by the PUCT in its final order. The final order in the CenterPoint case is expected to be issued later in November 2004. If the final order in the CenterPoint case resolves the existing uncertainties, TCC will record a carrying cost back to January 1, 2002 in the fourth quarter of 2004 as an increase to its net true-up regulatory asset. At this time we are unable to determine the amount of such carrying cost pending receipt of the final CenterPoint order.

Wholesale Capacity Auction True-up

The Texas Legislation required that electric utilities and their affiliated power generation companies (PGC) offer for sale at auction, in 2002, 2003 and thereafter, 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 are used to calculate the wholesale capacity auction true-up revenues for the True-up Proceeding. According to PUCT rules, the wholesale capacity auction true-up is only applicable to the years 2002 and 2003. TCC recorded a $480 million regulatory asset and related revenues which represent the quantifiable amount of the wholesale capacity auction true-up for the years 2002 and 2003.

In the true-up proceeding of CenterPoint, while the PUCT has indicated preliminary positions regarding modifications of the calculation of the wholesale capacity auction true-up reflecting CenterPoint's specific facts and circumstances, uncertainties exist as to the ultimate modifications and calculations that will be adopted by the PUCT in its final order and if TCC's facts and circumstances will result in similar results in its true-up proceeding. Specifically, the PUCT is evaluating whether the amount of depreciation in the ECOM model on generation assets for 2002 and 2003 used to calculate the wholesale capacity auction true-up is a recovery of net stranded generation costs and should reduce the recoverable cost. The total TCC depreciation in the ECOM Model for the 2002-2003 period was $238 million. Upon issuance of a final written order in the CenterPoint case, management will evaluate the order and, if appropriate, record a provision for any amount that is no longer probable of recovery as a result of final decisions in the order which are applicable to TCC. The CenterPoint order is expected to be issued later in November 2004.

Retail Clawback

The Texas Legislation provides for the affiliated price-to-beat (PTB) retail electric providers (REPs) serving residential and small commercial customers to refund to its T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. During 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. The PUCT approved TCC's and TNC's filings in December 2003. In 2002, AEP had accrued a regulatory liability of approximately $9 million for the small commercial retail clawback on its REP's books. When the PUCT certified that the REP's in TCC and TNC service territories had reached the 40% threshold, the regulatory liability was no longer required for the small commercial class and was reversed in December 2003. Based upon customer information filed by the unaffiliated company which operates as the price-to-beat REP for TCC and TNC, we updated the estimated residential retail clawback regulatory liability in May 2004. At September 30, 2004, TCC's retail clawback regulatory liability was $30 million and TNC's was $7 million.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the True-up Proceeding. In January 2004, the PUCT announced a final ruling in TNC's fuel reconciliation case. The PUCT issued a written order in March 2004. Various parties, including TNC, requested rehearing of the PUCT's order. In May 2004, the PUCT reversed certain prior rulings which resulted in an over-recovered balance of $7 million. In October 2004, the PUCT issued a final order which resulted in a reduction in the over-recovery balance to $4 million. TNC filed an update to its true-up filing to reflect the PUCT's final order in October 2004.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery fuel balance for inclusion in the True-up Proceeding. In May 2004, the PUCT remanded TCC's fuel proceeding to the ALJ to consider additional evidence on one issue. TCC has provided for a $210 million over-recovery balance at September 30, 2004. Management believes that TCC has provided for all probable to-date disallowances pending the remand and receipt of a final order. However, due to the remand, management is unable to predict the amount of any additional disallowances of TCC's final fuel over-recovery balance which will be included in its True-up Proceeding until the remand is completed and a final order issued.

See TCC Fuel Reconciliation and TNC Fuel Reconciliation in Note 3 "Rate Matters" for further discussion.

Stranded Cost Recovery

When the True-up Proceeding is completed, TCC intends to file to recover PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying charges, through a non-bypassable competition transition charge in the regulated T&D rates. TCC intends to seek to securitize the approved net stranded generation costs plus related carrying costs. The annual costs of securitization are recovered through a non-bypassable transition charge collected by the T&D utility over the term of the securitization bonds. The other approved net true-up items will be recovered or refunded through a non-bypassable competition transition wires charge or credit.

TCC's recorded net regulatory asset for amounts subject to approval in the True-up Proceeding is approximately $1.5 billion at September 30, 2004. We expect that TCC's True-up Proceeding filing will seek to recover an amount in excess of the total of its recorded net regulatory asset through September 30, 2004. This is primarily due to the fact that TCC has not been able to accrue a carrying cost to date as a result of uncertainties that exist. Management expects to be able to record a carrying cost in the fourth quarter of 2004 based on the final order in the CenterPoint case.

Due to the preliminary nature of the pending CenterPoint proceedings and the consequent uncertainty, differences between CenterPoint's and TCC's facts and circumstances and the lack of direct applicability of the CenterPoint proceeding to TCC's recorded assets, we cannot, at this time, determine whether disallowances that may be applicable to CenterPoint would be applicable to TCC. We believe that our recorded regulatory assets are in compliance with Texas Legislation and we intend to seek vigorously recovery of all of these amounts. If, however, we determine that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.5 billion and we are able to estimate the amount of such non-recovery, we will record a provision for such amount which could have a material adverse effect on future results of operations, cash flows and possibly financial condition. To the extent decisions in the TCC True-up Proceeding differ from management expectations based in part on our evaluation of the final CenterPoint decision, additional material disallowances are possible.

TNC 2004 True-up Filing

In June 2004, TNC filed its True-up Proceeding including the fuel reconciliation balance and the retail clawback calculation. The amount of the deferred over recovered fuel balance recorded at September 30, 2004 was approximately $7 million. The retail clawback regulatory liability included in the filing was adjusted in the second quarter of 2004 to $7 million (TNC's allocated portion of the REPs' retail clawback) reflecting the number of customers served on January 1, 2004. TNC filed an update to the true-up filing to reflect the final order in its fuel reconciliation proceeding in October 2004 which adjusted its over-recovery balance to $4.7 million inclusive of interest.

VIRGINIA RESTRUCTURING

In April 2004, the Governor of Virginia signed legislation which extends the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within our 2003 Annual Report, we continue to be involved in various legal matters. The 2003 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since our disclosure in the 2003 Annual Report. The material matters discussed in the 2003 Annual Report without significant changes in status since year-end include, but are not limited to, (1) nuclear matters, (2) construction commitments, (3) potential uninsured losses, (4) California lawsuits, (5) Bank of Montreal Claim, and (6) FERC proposed Standard Market Design. See disclosure below for significant matters with changes in status subsequent to the disclosure made in our 2003 Annual Report.

Environmental

Federal EPA Complaint and Notice of Violation

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

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

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

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 was scheduled for July 2004, but has been postponed until January 2005 to facilitate further settlement negotiations.

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

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, an unaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that the Federal EPA bears the burden of proof on the issue of whether a practice is "routine maintenance, repair, or replacement" and on whether or not a "significant net emissions increase" results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is "routine within the relevant source category" in determining if it is "routine." Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals, and the District Court denied the Federal EPA's motion. On April 13, 2004, the parties filed a joint motion for entry of final judgment, based on stipulations of relevant facts that obviated the need for a trial, but preserving plaintiffs' right to seek an appeal of the federal prevention of significant deterioration (PSD) claims. On April 14, 2004, the Court entered final judgment for Duke Energy on all of the PSD claims made in the amended complaints, and dismissed all remaining claims with prejudice. The United States subsequently filed a notice of appeal to the Fourth Circuit Court of Appeals. The case was briefed in September 2004.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for alleged CAA violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the CAA are unconstitutional. The United States filed a petition for certiorari with the United States Supreme Court and on May 3, 2004, that petition was denied.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which our subsidiaries are members, to reopen petitions for review of the 1980 and 1992 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. Briefing continues in this case and oral argument is scheduled for January 2005.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines "routine maintenance repair and replacement" to include "functionally equivalent equipment replacement." Under the new 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 a prospective effect, and was to become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003, twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

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

In December 2000, Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

On July 21, 2004, the Sierra Club issued a notice of intent to file a citizen suit claim against DPL, Inc., Cinergy Corporation, CSPCo, and The Dayton Power & Light Company for alleged violations of the New Source Review programs at the Stuart Station. CSPCo owns a 26% share of the Stuart Station. On September 21, 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio state implementation plan occurred at the J.M. Stuart Station, and seeking injunctive relief and civil penalties. We believe the allegations in the complaint are without merit, and intend to defend vigorously this action. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the Clean Air Act for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. No action can be commenced until 60 days after the date of notice.

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

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox

Lee Plant. On August 30, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the reporting of volatile organic compound emissions at the Pirkey Plant.

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

Carbon Dioxide Public Nuisance Claims

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

Nuclear Decommissioning

As discussed in the 2003 Annual Report, decommissioning costs are accrued over the service life of STP. The licenses to operate the two nuclear units at STP expire in 2027 and 2028. TCC had estimated its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year.

In May 2004, an updated decommissioning study was completed for STP. The study estimates TCC's share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. We are currently analyzing the STP study to determine the effect on our asset retirement obligations (ARO) and will make any appropriate adjustments to the ARO liability and related regulatory asset in the fourth quarter 2004. As discussed in Note 7, TCC is in the process of selling its ownership interest in STP to a non-affiliate, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

Operational

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004. The initial term of our lease with Juniper (Juniper Lease) commenced on March 18, 2004 and terminates on June 17, 2009. We may extend the term of the Juniper Lease for up to 30 years. Our lease of the Facility is reported as an owned asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on our balance sheet.

Juniper is an unaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing.

At September 30, 2004, Juniper's acquisition costs for the Facility totaled $520 million, and we estimate total costs for the completed Facility to be approximately $525 million, funded through long-term debt financing of $494 million and equity of $31 million from investors with no relationship to AEP or any of our subsidiaries. For the initial 5-year lease term, the base lease rental is equal to the interest on Juniper's debt financing at a variable rate indexed to three-month LIBOR (1.975% on September 30, 2004) plus 100 basis points, plus a fixed return on Juniper's equity investment in the Facility and certain other fixed amounts. Consequently, as LIBOR increases, the base rental payments under the Juniper Lease will also increase.

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

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

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

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

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

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

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In August 2004 the SEC announced it would conduct hearings on this issue. The hearing is scheduled for January 2005.

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUHCA's single region requirement. In its ruling, the appeals court said that the SEC failed to support and explain its conclusions that the interconnection and single region requirements are satisfied.

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

Enron Bankruptcy

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

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

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

Enron Bankruptcy - Right to use of cushion gas agreements - In connection with the 2001 acquisition of HPL, we also entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 BCF of cushion gas (the 10.5 BCF and 55 BCF described in the preceding paragraph) required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

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

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

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

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

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

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

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, lawsuits alleging securities law violations and seeking class action certification were filed in federal District Court, Columbus, Ohio against AEP, certain AEP executives, and in some of the lawsuits, members of the AEP Board of Directors and certain investment banking firms. The lawsuits claim that we failed to disclose that alleged "round trip" trades resulted in an overstatement of revenues, that we failed to disclose that our traders falsely reported energy prices to trade publications that published gas price indices and that we failed to disclose that we did not have in place sufficient management controls to prevent "round trip" trades or false reporting of energy prices. The plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. The Court appointed a lead plaintiff who filed a Consolidated Amended Complaint. We 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 and the Court denied plaintiff's motion to remand the case to state court. In September 2004, the U.S. District Court Judge dismissed the cases and expressly denied the plaintiffs' request for an opportunity to file amended complaints with new or revised allegations. Plaintiffs did not appeal this decision.

In the fourth quarter of 2002, two shareholder derivative actions were filed in state court in Columbus, Ohio against AEP and its Board of Directors alleging a breach of fiduciary duty for failure to establish and maintain adequate internal controls over our gas trading operations. These cases have been stayed pending the outcome of our Motion to Dismiss the Consolidated Amended Complaint in the federal securities lawsuits. In October 2004 plaintiffs agreed to dismiss these cases. Also, in the fourth quarter of 2002 and the first quarter of 2003, three putative class action lawsuits were filed against AEP, certain AEP 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 filed a Motion to Dismiss these actions, which the Court denied. We have filed a Motion for Leave to file an interlocutory appeal seeking review of part of the Court's decision. The cases are in the discovery stage. We intend to continue to defend vigorously against these claims.

Cornerstone Lawsuit

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

Texas Commercial Energy, LLP Lawsuit

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

Energy Market Investigation

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

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. We responded to the complaint in September 2004. In 2003 we recorded a provision related to these matters. We have engaged in settlement discussions with several agencies and are evaluating whether to conclude settlements in order to put these investigations behind us even though we believe we have meritorious legal positions and defenses. If we elect to settle all matters, the payments could exceed the 2003 provision and could have a material impact on our 2004 earnings and cash flows.

FERC Market Power Mitigation

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. These two screening tests include a "pivotal supplier" test which determines if the market load can be fully served by alternative suppliers and a "market share" test which compares the amount of surplus generation at the time of the applicant's minimum load. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order and directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way.

On August 9, 2004, AEP submitted its Market Power Analysis pursuant to the FERC's Orders on Rehearing. The analysis focused on the three major areas in which AEP serves load and owns generation resources -- ECAR, SPP and ERCOT, and the "first tier" control areas for each of those areas.

The pivotal supplier and market share screen analyses that AEP filed demonstrated that AEP does not possess market power in any of the control areas to which it is directly connected (first-tier markets). AEP passed both screening tests in all of its "first tier" markets. In its three "home" control areas, AEP easily passed the pivotal supplier test. AEP, as part of PJM, also passes the market share screen for the PJM destination market. AEP also passed the market share screen for ERCOT. AEP did not pass the market share screen as designed by the FERC for the SPP control area. Consequently, AEP also submitted substantial additional information, including historical purchase and sales data that demonstrates that AEP does not possess market power in any of the "home" destination markets. AEP requested that its existing market-based pricing authorization in all markets be continued based on this analysis. AEP also requested that the FERC rule without instituting a proceeding and without setting a refund date. This case is pending.

6. GUARANTEES

There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002 in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others." There is no collateral held in relation to any guarantees in excess of our ownership percentages and there is no recourse to third parties in the event any guarantees are drawn unless specified below.

LETTERS OF CREDIT

We have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. We issued all of these LOCs in our ordinary course of business. At September 30, 2004, the maximum future payments for all the LOCs were approximately $202 million with maturities ranging from October 2004 to January 2011. As the parent of various subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these LOCs are drawn.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

CSW Energy and CSW International

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

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $54 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, 2004, 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.

Effective July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46. SWEPCo does not have an ownership interest in Sabine.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We entered into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. We cannot estimate the maximum potential exposure for any of these indemnifications entered into prior to December 31, 2002 due to the uncertainty of future events. In 2003 and during the first nine months of 2004, we entered into several sale agreements. These sale agreements include indemnifications with a maximum exposure of approximately $963 million. There are no material liabilities recorded for any indemnifications entered during 2003 or the first nine months of 2004. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At September 30, 2004, the maximum potential loss for this lease agreement was approximately $43 million ($28 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

Railcar Lease

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

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal a minimum lessee obligation amount specified in the lease, which declines over the term from approximately 86% to 77% of the projected fair market value of the equipment. At September 30, 2004, 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 terms to an unaffiliated company under an operating lease. The sublessee has recently renewed for an additional year and may renew the lease for up to three more additional one-year terms.

7. DISPOSITIONS, DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

DISPOSITION COMPLETED DURING FIRST QUARTER 2004

Pushan Power Plant (Investments - Other segment)

In the fourth quarter of 2002, we began active negotiations to sell our interest in the Pushan Power Plant (Pushan) in Nanyang, China to our minority interest partner. A purchase and sale agreement was signed in the fourth quarter of 2003. The sale was completed in March 2004 for $60.7 million. An estimated loss on disposal of $20 million pre-tax ($13 million after-tax) was recorded in December 2002, based on an indicative price expression at that time, and was classified in Discontinued Operations. The effect of the sale on the first quarter 2004 results of operations was not significant.

Results of operations of Pushan have been reclassified as Discontinued Operations. The assets and liabilities of Pushan have been included in Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held For Sale, respectively, on our Consolidated Balance Sheet at December 31, 2003.

DISPOSITIONS COMPLETED DURING SECOND QUARTER 2004

LIG Pipeline Company and its Subsidiaries (Investments - Gas Operations segment)

As a result of our 2003 decision to exit our non-core businesses, we actively marketed LIG Pipeline Company which possesses approximately 2,000 miles of natural gas gathering and transmission pipelines in Louisiana and five gas processing facilities that straddle the system. For the year ended December 31, 2003, LIG's assets were classified as held for sale and their operations were shown under Discontinued Operations. In January 2004, a decision was made to sell LIG's pipeline and processing assets separate from LIG's gas storage assets. After receiving and analyzing initial bids during the fourth quarter of 2003, we recorded a $133.9 million pre-tax ($99 million after-tax) impairment loss; of this loss, $128.9 million pre-tax relates to the impairment of goodwill and $5 million pre-tax relates to other charges. In February 2004, we signed a definitive agreement to sell LIG Pipeline Company, which owned all of the pipeline and processing assets of LIG. The sale of LIG Pipeline Company and its assets for $76.2 million was completed in April 2004 and the impact on results of operations in the second quarter of 2004 was not significant. The assets and liabilities of LIG are classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively on our Consolidated Balance Sheets at December 31, 2003. The results of operations (including the above-mentioned impairments and other related charges) are classified in Discontinued Operations in our Consolidated Statements of Operations for the periods ending September 30, 2004 and 2003.

AEP Coal (Investments - Other segment)

In 2003, as a result of management's decision to exit our non-core businesses, we retained an advisor to facilitate the sale of AEP Coal. In March 2004, an agreement was reached to sell assets, exclusive of certain reserves and related liabilities, of the mining operations of AEP Coal. We received approximately $8.8 million cash and the buyer assumed an additional $11.1 million in future reclamation liabilities. We retained an estimated $36.7 million in future reclamation liabilities. The sale closed in April 2004 and the effect of the sale on second quarter 2004 results of operations was not significant. The assets and liabilities of AEP Coal have been included in Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, in our Consolidated Balance Sheet at December 31, 2003.

DISPOSITIONS COMPLETED DURING THIRD QUARTER 2004

Independent Power Producers (Investments - Other segment)

During the third quarter of 2003, we initiated an effort to sell four domestic Independent Power Producer (IPP) investments accounted for under the equity method (two located in Colorado and two located in Florida). Our two Colorado investments include a 47.75% interest in Brush II, a 68-megawatt, gas-fired, combined cycle, cogeneration plant in Brush, Colorado and a 50% interest in Thermo, a 272-megawatt, gas-fired, combined cycle, cogeneration plant located in Ft. Lupton, Colorado. Our two Florida investments include a 46.25% interest in Mulberry, a 120-megawatt, gas-fired, combined cycle, cogeneration plant located in Bartow, Florida and a 50% interest in Orange, a 103-megawatt, gas-fired, combined cycle, cogeneration plant located in Bartow, Florida. In accordance with GAAP, we were required to measure the impairment of each of these four investments individually. Based on indicative bids, it was determined that an other than temporary impairment existed on the two equity method investments located in Colorado. The $70.0 million pre-tax ($45.5 million, net of tax) impairment recorded in September 2003 was the result of the measurement of fair value that was triggered by our decision to sell these assets. This loss of investment value was included in Investment Value Losses on our Consolidated Statements of Operations for the periods ending September 30, 2003.

In March 2004, we entered into an agreement to sell the four domestic IPP investments for a total sales price of $156 million, subject to closing adjustments. An additional pre-tax impairment of $1.6 million was recorded in June 2004 (recorded to Investment Value Losses) to decrease the carrying value of the Colorado plant investments to their estimated sales price, less selling expenses. We closed on the sale of the two Florida investments and the Brush II plant in Colorado in July 2004, resulting in a pre-tax gain of $104.6 million ($63.8 million, net of tax), generated primarily from the sale of the two Florida IPPs which were not originally impaired. The gain was recorded to Other Income (Expense), Net in our Consolidated Statements of Operations in July 2004. The sale of the Ft. Lupton, Colorado plant closed in October 2004 and will not have a significant effect on results of operations for the fourth quarter 2004. Prior to the completion of the sale of each of the four IPPs, the assets for each of the four IPPs have been included in Investments in Power and Distribution Projects.

U.K. Generation (Investments - UK Operations segment)

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

In the fourth quarter of 2003, the U.K. generation plants were determined to be non-core assets and management engaged an investment advisor to assist in determining the best methodology to exit the U.K. business. Based on information received, we recorded a $577 million pre-tax charge ($375 after-tax), including asset impairments of $420.7 million during the fourth quarter of 2003 to write down the value of the assets to their estimated realizable value. Additional charges of $156.7 million pre-tax were also recorded in December 2003 including $122.2 million related to the net loss on certain cash flow hedges previously recorded in Accumulated Other Comprehensive Income (Loss) that have been reclassified into earnings as a result of management's determination that the hedged event is no longer probable of occurring and $34.5 million related to a first quarter 2004 sale of certain power contracts. All write downs related to the U.K. that were booked in the fourth quarter 2003 were included in Discontinued Operations of our Consolidated Statements of Operations for the year ended 2003.

In July 2004, we completed the sale of substantially all operations and assets within the U.K. The sale included our two coal-fired generation plants (Fiddler's Ferry and Ferrybridge) that were held-for-sale as described above, related coal assets, and a number of related commodities contracts for approximately $456 million. The sale resulted in a pre-tax gain of $266 million ($127 million, net of tax). As a result of the sale, the buyer assumed an additional $46.1 million in future reclamation liabilities and $10.2 million in pension liabilities. The remaining assets and liabilities include certain physical coal, power and capacity positions and financial coal and freight swaps. The majority of these positions will either mature or be settled with the applicable counterparties during the fourth quarter 2004. The assets and liabilities of U.K. Generation have been classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on our Consolidated Balance Sheets at September 30, 2004 and December 31, 2003. The results of operations and gain on sale are included in Discontinued Operations on our Consolidated Statements of Operations for the periods ending September 30, 2004 and 2003.

Texas Plants - TCC Generation Assets (Utility Operations segment)

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as "reliability must run" status.

During the fourth quarter of 2003, after receiving indicative bids from interested buyers, we recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to Assets of Discontinued Operations and Held for Sale. In accordance with Texas legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the True-up Proceeding. As a result of the True-up Proceeding, if we are unable to recover all or a portion of our requested costs (see Note 4), any unrecovered costs could have a material adverse effect on our results of operations, cash flows and possibly financial condition.

In March 2004, we signed an agreement to sell eight natural gas plants, one coal-fired plant and one hydro plant to a non-related joint venture. The sale was completed in July 2004 for approximately $425 million, net of adjustments. The sale did not have a significant effect on our results of operations during the periods ended September 30, 2004.

South Coast Power Limited (Investments - Other Segment)

South Coast Power Limited (SCPL) is a 50% owned venture that was formed in 1996 to build, own and operate Shoreham Power Station, a 400-megawatt, combined-cycle, gas turbine power station located in Shoreham, England. In 2002, SCPL was subject to adverse wholesale electric power rates. A December 2002 projected cash flow estimate of the fair value of the investment indicated a 2002 pre-tax other than temporary impairment of the equity interest in the amount of $63.2 million. This loss of investment value was included in Investment Value and Other Impairment Losses in the 2002 Consolidated Statements of Operations.

In the fourth quarter of 2003, management determined that our U.K. operations were no longer part of our core business and as a result, a decision was made to exit the U.K. market. In September 2004, we completed the sale of our 50% ownership in SCPL for $46.9 million, resulting in an estimated $47.6 million net gain ($30.9 million, net of tax) in the third quarter 2004. This gain was recorded to Other Income (Expense), Net in our Consolidated Statements of Operations for the periods ended September 30, 2004. The gain reflects improved conditions in the U.K. power market.

DISPOSITIONS COMPLETED OR ANTICIPATED BEING COMPLETED DURING FOURTH QUARTER 2004

Jefferson Island Storage & Hub, L.L.C. (Investments - Gas Operations segment)

In August 2004, a definitive agreement was signed to sell the gas storage assets of Jefferson Island Storage & Hub, L.L.C. (JISH). The sale of JISH and its assets for $90.3 million was completed in October 2004. The sale resulted in an additional $12.3 million pre-tax loss ($2 million, net of tax) which is reflected in our third quarter 2004 Consolidated Statements of Operations. The assets and liabilities of JISH are classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on our Consolidated Balance Sheets as of September 30, 2004 and December 31, 2003. The results of operations and loss on sale of JISH are classified as Discontinued Operations in our Consolidated Statements of Operations for the periods ending September 30, 2004 and 2003.

Excess Real Estate (Investments - Other segment)

In the fourth quarter of 2002, we began to market an under-utilized office building in Dallas, Texas obtained through our merger with CSW in June 2000. One prospective buyer executed an option to purchase the building. Sale of the facility was projected by second quarter 2003 and an estimated 2002 pre-tax loss on disposal of $15.7 million was recorded, based on the option sale price. The estimated loss was included in Impairment Value and Other Impairment Losses in our 2002 Consolidated Statements of Operations. We recorded an additional pre-tax impairment of $6 million in Maintenance and Other Operation in our 2003 Consolidated Statements of Operations. The original prospective buyer did not complete their purchase of the building by the end of 2003, and thus, the asset no longer qualified for held for sale status. The building was then reclassified to held and used status as of December 31, 2003.

In June 2004, we entered into negotiations to sell the Dallas office building. This resulted in the asset again being classified as held for sale in the second quarter of 2004. An additional pre-tax impairment of $2.5 million was recorded in Maintenance and Other Operation expense during the second quarter of 2004 to write down the value of the office building to the current estimated sales price, less estimated selling expenses. In October 2004, we completed the sale of the Dallas office building. We do not expect the sale to have a significant effect on our results of operations. The property asset of $9.5 million at September 30, 2004 and $12.0 million at December 31, 2003 has been classified on our Consolidated Balance Sheets as Assets of Discontinued Operations and Held for Sale.

DISPOSITIONS ANTICIPATED BEING COMPLETED DURING FIRST HALF 2005

Texas Plants - Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. In May 2004, we received notice from the two unaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal, with terms similar to the original agreement. In June 2004 and September 2004, we entered into sales agreements with both of our unaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. One of these agreements is currently being challenged in Dallas County, Texas State District Court by the unrelated party with which we entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners' exercise of their rights of first refusal void. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on our future results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, in our Consolidated Balance Sheets at September 30, 2004 and December 31, 2003.

Texas Plants - South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCC's 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal, with terms similar to the original agreement. In September 2004, we entered into sales agreements with two of our unaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. We do not expect the sale to have a significant effect on our future results of operations. We expect the sale to close in the first six months of 2005. TCC's assets and liabilities related to STP have been classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, in our Consolidated Balance Sheets at September 30, 2004 and December 31, 2003.

DISCONTINUED OPERATIONS

Certain of our operations were determined to be discontinued operations and have been classified as such for all periods presented. Results of operations of these businesses have been reclassified for the three and nine month periods ended September 30, 2004 and 2003, as shown in the following table:

For the three months ended September 30, 2004 and 2003:

	Eastex	Pushan Power Plant	LIG (a)	U.K. Generation	Total
			(in millions)		
2004 Revenue	$-	$-	$1	$37	$38
2004 Pre-tax Income (Loss)	-	-	(13)	255	242
2004 Income (Loss) After-Tax	-	1	(3)	120 (b)	118

2003 Revenue	12	14	165	4	195
2003 Pre-tax Income (Loss)	(1)	-	2	(76)	(75)
2003 Income (Loss) After-Tax	-	-	2	(52)(c)	(50)

For the nine months ended September 30, 2004 and 2003:

	Eastex	Pushan Power Plant	LIG (a)	U.K. Generation	Total
			(in millions)		
2004 Revenue	$-	$10	$165	$112	$287
2004 Pre-tax Income (Loss)	-	9	(12)	156	153
2004 Income (Loss) After-Tax	-	6	(2)	56 (d)	60
2003 Revenue	58	41	518	116	733
2003 Pre-tax Income (Loss)	(24)	-	8	(112)	(128)
2003 Income (Loss) After-Tax	(15)	-	6	(89)(e)	(98)

(a) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub, L.L.C.
(b) Earnings per share related to the UK Operations was $0.30
(c) Earnings per share related to the UK Operations was $(0.13)
(d) Earnings per share related to the UK Operations was $0.14
(e) Earnings per share related to the UK Operations was $(0.23)

ASSETS OF DISCONTINUED OPERATIONS AND HELD FOR SALE

The assets and liabilities of the entities that were classified as discontinued operations or held for sale at September 30, 2004 and December 31, 2003 are as follows:

September 30, 2004	U.K. Generation	Texas Plants	Excess Real Estate	Jefferson Island	Total
Assets:			(in millions)		
Current Risk Management Assets	$85	$-	$-	$-	$85
Other Current Assets	81	24	-	2	107
Property, Plant and Equipment, Net	-	398	10	70	478
Regulatory Assets	-	53	-	-	53
Decommissioning Trusts	-	134	-	-	134
Goodwill	-	-	-	14	14
Long-term Risk Management Assets	4	-	-	-	4
Other	5	-	-	7	12
Total Assets of Discontinued Operations and Held for Sale	$175	$609	$10	$93	$887
Liabilities:					
Current Risk Management Liabilities	$80	$-	$-	$-	$80
Other Current Liabilities	61	-	-	2	63
Long-term Risk Management Liabilities	11	-	-	-	11
Regulatory Liabilities	-	1	-	-	1
Asset Retirement Obligations	-	231	-	-	231
Total Liabilities of Discontinued Operations and Held for Sale	$152	$232	$-	$2	$386

December 31, 2003	AEP Coal	Pushan Power Plant	LIG (excluding Jefferson Island)	U.K. Generation	Texas Plants	Excess Real Estate	Jefferson Island	Total
Assets:				(in millions)				
Current Risk Management Assets	$-	$-	$-	$560	$-	$-	$-	$560
Other Current Assets	6	24	49	685	57	-	1	822
Property, Plant and Equipment, Net	13	142	109	99	797	12	62	1,234
Regulatory Assets	-	-	-	-	49	-	-	49
Decommissioning Trusts	-	-	-	-	125	-	-	125
Goodwill	-	-	1	-	-	-	14	15
Long-term Risk Management Assets	-	-	-	274	-	-	-	274
Other	-	-	8	6	-	-	1	15
Total Assets of Discontinued Operations and Held for Sale	$19	$166	$167	$1,624	$1,028	$12	$78	$3,094

Liabilities:								
Current Risk Management Liabilities	$-	$-	$15	$767	$-	$-	$-	$782
Other Current Liabilities	-	26	42	221	-	-	4	293
Long-term Debt	-	20	-	-	-	-	-	20
Long-term Risk Managemen Liabilities	-	-	-	435	-	-	-	435
Regulatory Liabilities	-	-	-	-	9	-	-	9
Asset Retirement Obligations	11	-	-	29	219	-	-	259
Employee Pension Obligations	-	-	-	12	-	-	-	12
Deferred Credits and Other	3	57	6	-	-	-	-	66
Total Liabilities of Discontinued Operations and Held for Sale	$14	$103	$63	$1,464	$228	$-	$4	$1,876

8. BENEFIT PLANS

Components of Net Periodic Benefit Costs

The following table provides the components of our net periodic benefit cost (credit) for the following plans for the three and nine months ended September 30, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
Three Months ended September 30, 2004 and 2003:	(in millions)			
Service Cost	$22	$20	$10	$10
Interest Cost	57	58	29	33
Expected Return on Plan Assets	(73)	(79)	(20)	(16)
Amortization of Transition (Asset) Obligation	-	(2)	7	7
Amortization of Net Actuarial Loss	4	3	9	13
Net Periodic Benefit Cost	$10	$-	$35	$47

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
Nine Months ended September 30, 2004 and 2003:	(in millions)			
Service Cost	$65	$60	$30	$31
Interest Cost	171	175	88	98
Expected Return on Plan Assets	(219)	(238)	(61)	(48)
Amortization of Transition (Asset) Obligation	1	(6)	21	21
Amortization of Prior Service Cost	-	(1)	-	-
Amortization of Net Actuarial Loss	12	8	27	39
Net Periodic Benefit Cost (Credit)	$30	$(2)	$105	$141

In accordance with our implementation of FASB Staff Position FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," in the second quarter 2004, accounting for the Medicare subsidy reduced expected 2004 postretirement benefit cost by $29 million. As a result, expected cash flows for 2004 employer contributions to U.S. other postretirement benefit plans have been reduced by $29 million from the $180 million disclosed at December 31, 2003. Including an additional $19 million reduction related to refining earlier estimates, we currently expect to contribute approximately $132 million to our U.S. other postretirement benefit plans during 2004.

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

Investments - Gas Operations*
o Gas pipeline and storage services

Investments - UK Operations**
o International generation of electricity for sale to wholesale customers
o Coal procurement and transportation to our U.K. plants

Investments - Other***
o Bulk commodity barging operations, windfarms, independent power producers and other energy supply businesses

* Operations of Louisiana Intrastate Gas, including Jefferson Island Storage, were classified as discontinued during 2003 and were sold during the third and fourth quarter 2004, respectively. ** UK Operations were classified as discontinued during 2003 and were sold during third quarter 2004. *** Four independent power producers were sold during the third and fourth quarter 2004.

The tables below present segment income statement information for the three and nine months ended September 30, 2004 and 2003 and balance sheet information as of September 30, 2004 and December 31, 2003. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other*	Reconciling Adjustments	Consolidated
				(in millions)			
Three Months Ended September 30, 2004							
Revenues from:							
External Customers	$2,909	$762	$-	$81	$-	$-	$3,752
Other Operating Segments	37	(16)	-	17	1	(39)	-
Total Revenues	2,946	746	-	98	1	(39)	3,752
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes	359	(28)	-	90	(9)	-	412
Discontinued Operations, Net of Tax	-	(3)	120	1	-	-	118
Net Income (Loss)	$359	$(31)	$120	$91	$(9)	$-	$530
As of September 30, 2004							
Total Assets	$31,403	$2,099	$273	$1,447	$10,635	$(11,035)	$34,822
Assets of Discontinued Operations and Held for Sale	609	93	175	-	10	-	887

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other*	Reconciling Adjustments	Consolidated
				(in millions)			
Three Months Ended September 30, 2003							
Revenues from:							
External Customers	$3,099	$707	$-	$135	$-	$-	$3,941
Other Operating Segments	13	66	-	29	3	(111)	-
Total Revenues	3,112	773	-	164	3	(111)	3,941
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes	409	(21)	-	(45)	(36)	-	307
Discontinued Operations, Net of Tax	-	2	(52)	-	-	-	(50)
Net Income (Loss)	$409	$(19)	$(52)	$(45)	$(36)	$-	$257
As of December 31, 2003							
Total Assets	$30,790	$2,494	$1,629	$1,714	$12,281	$(12,164)	$36,744
Assets of Discontinued							

Operations and Held for Sale	1,028	245	1,624	185	12	-	3,094

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other*	Reconciling Adjustments	Consolidated
				(in millions)			
Nine Months Ended September 30, 2004							
Revenues from:							
External Customers	$7,989	$2,191	$-	$281	$-	$-	$10,461
Other Operating Segments	106	23	-	67	5	(201)	-
Total Revenues	8,095	2,214	-	348	5	(201)	10,461
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes	845	(41)	-	91	(43)	-	852
Discontinued Operations, Net of Tax	-	(2)	56	6	-	-	60
Net Income (Loss)	$845	$(43)	$56	$97	$(43)	$-	$912
As of September 30, 2004							
Total Assets	$31,403	$2,099	$273	$1,447	$10,635	$(11,035)	$34,822
Assets of Discontinued Operations and Held for Sale	609	93	175	-	10	-	887

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other*	Reconciling Adjustments	Consolidated
				(in millions)			
Nine Months Ended September 30, 2003							
Revenues from:							
External Customers	$8,458	$2,278	$-	$440	$-	$-	$11,176
Other Operating Segments	25	118	-	72	10	(225)	-
Total Revenues	8,483	2,396	-	512	10	(225)	11,176
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes	940	(64)	-	(45)	(54)	-	777
Discontinued Operations, Net of Tax	-	6	(89)	(15)	-	-	(98)
Cumulative Effect of Accounting Changes, Net of Tax	236	(22)	(21)	-	-	-	193
Net Income (Loss)	$1,176	$(80)	$(110)	$(60)	$(54)	$-	872
As of December 31, 2003							
Total Assets	$30,790	$2,494	$1,629	$1,714	$12,281	$(12,164)	$36,744
Assets of Discontinued Operations and Held for Sale	1,028	245	1,624	185	12	-	3,094

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

10. FINANCING ACTIVITIES

Long-term debt and other securities issued and retired during the first nine months of 2004 are shown in the table below.

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	
Issuances:				
APCo	Senior Unsecured Notes	$125	Variable	2007
CSPCo	Installment Purchase Contracts	49	Variable	2038
CSPCo	Installment Purchase Contracts	44	Variable	2038
PSO	Installment Purchase Contracts	34	Variable	2014
PSO	Senior Unsecured Notes	50	4.70	2009
SWEPCo	Installment Purchase Contracts	54	Variable	2019

SWEPCo	Installment Purchase Contracts	41	Variable	2011
Non-Registrant:				
AEP Subsidiary	Notes Payable	23	Variable	2009
AEP Subsidiaries	Other Debt	5	Variable	Various
Total Issuances		$425 (a)		

(a) Amount indicated on statement of cash flows of $416 million is net of issuance costs.

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Retirements:				
AEP	Senior Unsecured Notes	$57	5.25	2015
AEP	Senior Unsecured Notes	10	5.375	2010
APCo	First Mortgage Bonds	21	7.70	2004
APCo	First Mortgage Bonds	45	7.125	2024
APCo	Installment Purchase Contracts	40	5.45	2019
CSPCo	First Mortgage Bonds	11	7.60	2024
CSPCo	Installment Purchase Contracts	49	6.375	2020
CSPCo	Installment Purchase Contracts	44	6.25	2020
I&M	First Mortgage Bonds	30	7.20	2024
I&M	First Mortgage Bonds	25	7.50	2024
I&M	Senior Unsecured Notes	150	6.875	2004
OPCo	Installment Purchase Contracts	50	6.85	2022
OPCo	Notes Payable	3	6.27	2009
OPCo	Notes Payable	4	6.81	2008
OPCo	First Mortgage Bonds	10	7.30	2024
OPCo	Senior Unsecured Notes	140	7.375	2038
OPCo	Senior Unsecured Notes	100	6.75	2004
OPCo	Senior Unsecured Notes	75	7.00	2004
PSO	Notes Payable to Trust	77	8.00	2037
PSO	Installment Purchase Contracts	1	5.90	2007
PSO	Installment Purchase Contracts	34	4.875	2014
SWEPCo	Installment Purchase Contracts	12	6.90	2004
SWEPCo	Installment Purchase Contracts	12	6.00	2008
SWEPCo	Installment Purchase Contracts	17	8.20	2011
SWEPCo	Installment Purchase Contracts	54	7.60	2019
SWEPCo	First Mortgage Bonds	80	6.875	2025
SWEPCo	First Mortgage Bonds	40	7.75	2004
SWEPCo	Notes Payable	5	4.47	2011
SWEPCo	Notes Payable	2	Variable	2008
TCC	Notes Payable to Trust	141	8.00	2037
TCC	First Mortgage Bonds	6	6.625	2005
TCC	Securitization Bonds	49	3.54	2005
TNC	First Mortgage Bonds	24	6.125	2004
Non-Registrant:				
AEP Subsidiaries	Notes Payable	40	6.73	2004
AEP Subsidiaries	Notes Payable and Other Debt	473	Variable	2007-2026
Total Retirements		$1,931 (b)		

(b) Amount indicated on statement of cash flows of $1,898 million does not include $25 million related to retirement of debt of a discontinued operation, $5 million related to the reacquisition of TCC's notes payable to trust and $3 million related to the mark-to-market of risk management contracts.

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Defeasance:				
TCC	First Mortgage Bonds	$27	7.25	2004
TCC	First Mortgage Bonds	66	6.625	2005
TCC	First Mortgage Bonds	19	7.125	2008
Total Defeased		$112 (c)		

(c) Trust fund assets for defeasance of First Mortgage Bonds of $100 million are included in Other Cash Deposits and $22 million are included in Other Non-current Assets in the Consolidated Balance Sheets at September 30, 2004. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Operating revenues are derived from the sale of our share of Rockport Plant energy and capacity to I&M and KPCo pursuant to FERC approved long-term unit power agreements. The unit power agreements provide for a FERC approved rate of return on common equity, a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes.

Net Income increased $383 thousand for the third quarter of 2004 compared with the third quarter of 2003 and increased $152 thousand for the nine months ended September 30, 2004 compared with the nine months ended September 30, 2003. The fluctuations in Net Income are a result of terms in the unit power agreements which allow for the return on total capital of the Rockport Plant calculated and adjusted monthly.

Third Quarter 2004 Compared to Third Quarter 2003

Operating Income

Operating Income increased $405 thousand for the third quarter of 2004 compared with the third quarter of 2003. The largest variances related to:

o A $6 million increase in Operating Revenues as a result of increased recoverable fuel expenses in accordance with the unit power agreements.
o A $5 million increase in Fuel for Electric Generation expenses. This increase is primarily due to fewer outages during third quarter 2004 resulting in a 5% higher MWH output combined with increasing fuel prices.
o A $1 million increase in Taxes Other Than Income Taxes as a result of State of Indiana property tax re-appraisals.
o A $1 million decrease in Maintenance expenses as a result of decreased outages compared to the prior year period.

Income Taxes

The effective tax rates for the third quarter of 2004 and 2003 were (2.7)% and
(10.7)% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is primarily due to amortization of investment tax credits, flow-through of book versus tax temporary differences, and state income taxes. The increase in the effective tax rate is primarily due to higher pre-tax income in 2004.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Operating Income

Operating Income was down slightly over the prior year period. The largest variances related to:

o An $8 million decrease in Fuel for Electric Generation expenses. This decrease is primarily due to a 14% decrease in MWH generation as a result of both planned and forced outages.
o A $4 million increase in Maintenance expenses as a result of increased planned boiler inspections and forced repairs.
o A $2 million decrease in Operating Revenues as a result of decreased recoverable expenses in accordance with the unit power agreements.
o A $1 million increase in Taxes Other Than Income Taxes as a result of State of Indiana property tax re-appraisals.

Income Taxes

The effective tax rates for the first nine months of 2004 and 2003 were (8.9)% and (14.1)% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is primarily due to amortization of investment tax credits, flow-through of book versus tax temporary differences, and state income taxes. The increase in the effective tax rate is primarily due to higher pre-tax income in 2004.

Off-balance Sheet Arrangements

In prior years, we entered into off-balance sheet arrangements. Our current policy restricts the use of off-balance sheet financing entities or structures, except for traditional operating lease arrangements. Our off-balance sheet arrangement has not changed significantly from year-end 2003 and is comprised of a sale and leaseback transaction entered into by AEGCo and I&M with an unrelated unconsolidated trustee. For complete information on this off-balance sheet arrangement see "Off-balance Sheet Arrangements" in "Management's Narrative Financial Discussion and Analysis" section of our 2003 Annual Report.

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets and the impact of new accounting pronouncements.

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended 2004	Three Months Ended 2003	Nine Months Ended 2004	Nine Months Ended 2003
	(in thousands)			
OPERATING REVENUES	$65,303	$59,008	$176,933	$179,004
OPERATING EXPENSES				
Fuel for Electric Generation	32,857	27,514	79,291	87,148
Rent - Rockport Plant Unit 2	17,071	17,071	51,212	51,212
Other Operation	2,472	2,691	7,628	7,683
Maintenance	1,835	2,461	10,025	6,399
Depreciation and Amortization	5,941	5,695	17,447	16,981
Taxes Other Than Income Taxes	2,070	1,085	3,956	2,480
Income Taxes	843	682	2,240	1,927
TOTAL	63,089	57,199	171,799	173,830
OPERATING INCOME	2,214	1,809	5,134	5,174
Nonoperating Income	-	3	43	24
Nonoperating Expenses	72	44	235	286
Nonoperating Income Tax Credits	905	878	2,709	2,617
Interest Charges	643	625	1,914	1,944
NET INCOME	$2,404	$2,021	$5,737	$5,585

STATEMENTS OF RETAINED EARNINGS
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended 2004	Three Months Ended 2003	Nine Months Ended 2004	Nine Months Ended 2003
	(in thousands)			
BALANCE AT BEGINNING OF PERIOD	$22,251	$19,384	$21,441	$18,163
Net Income	2,404	2,021	5,737	5,585
Cash Dividends Declared	1,262	1,172	3,785	3,515
BALANCE AT END OF PERIOD	$23,393	$20,233	$23,393	$20,233

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

See Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$668,336	$645,251
General	3,826	4,063
Construction Work in Progress	5,348	24,741
TOTAL	677,510	674,055
Accumulated Depreciation	363,050	351,062
TOTAL - NET	314,460	322,993
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	119	119
CURRENT ASSETS		
Accounts Receivable - Affiliated Companies	22,161	24,748
Fuel	18,837	20,139
Materials and Supplies	5,774	5,419
Prepayments	11	-
TOTAL	46,783	50,306
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,555	4,733
Asset Retirement Obligations	1,069	928
Deferred Property Taxes	1,344	502
Other Deferred Charges	429	464
TOTAL	7,397	6,627
TOTAL ASSETS	$368,759	$380,045

See Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - Par Value $1,000 per share:		
Authorized and Outstanding - 1,000 Shares	$1,000	$1,000
Paid-in Capital	23,434	23,434
Retained Earnings	23,393	21,441
Total Common Shareholder's Equity	47,827	45,875
Long-term Debt	44,818	44,811
TOTAL	92,645	90,686
CURRENT LIABILITIES		
Advances from Affiliates	15,497	36,892
Accounts Payable:		
General	543	498
Affiliated Companies	12,991	15,911
Taxes Accrued	10,039	6,070
Interest Accrued	456	911
Obligations Under Capital Leases	62	87
Rent Accrued - Rockport Plant Unit 2	23,427	4,963
Other	108	-
TOTAL	63,123	65,332
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	23,843	24,329
Regulatory Liabilities:		
Asset Removal Costs	25,414	27,822
Deferred Investment Tax Credits	47,087	49,589
SFAS 109 Regulatory Liability, Net	14,003	15,505
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	101,297	105,475
Obligations Under Capital Leases	154	182
Asset Retirement Obligations	1,193	1,125
TOTAL	212,991	224,027
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$368,759	$380,045

See Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$5,737	$5,585
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	17,447	16,981
Deferred Income Taxes	(1,987)	(3,268)
Deferred Investment Tax Credits	(2,502)	(2,503)
Deferred Property Taxes	(842)	(795)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(4,178)	(4,178)
Changes in Certain Assets and Liabilities:		
Accounts Receivable	2,587	(2,027)
Fuel, Materials and Supplies	947	5,165
Accounts Payable, Net	(2,875)	(1,757)
Taxes Accrued	3,969	2,033
Rent Accrued - Rockport Plant Unit 2	18,464	18,464
Change in Other Assets	2,395	1,383
Change in Other Liabilities	(2,734)	(558)
Net Cash Flows From Operating Activities	36,428	34,525
INVESTING ACTIVITIES		
Construction Expenditures	(11,248)	(9,855)
Net Cash Flows Used For Investing Activities	(11,248)	(9,855)
FINANCING ACTIVITIES		
Change in Advances from Affiliates	(21,395)	(21,155)
Dividends Paid	(3,785)	(3,515)
Net Cash Flows Used For Financing Activities	(25,180)	(24,670)
Net Decrease in Cash and Cash Equivalents	-	-
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$-	$-

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $2,170,000 and $2,200,000 and for income taxes was $87,000 and $5,939,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries.

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

The notes to AEGCo's financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to AEGCo.

Reference	Footnote
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Commitments and Contingencies	Note 5
Guarantees	Note 6
Business Segments	Note 9
Financing Activities	Note 10

Results of Operations

Net Income decreased $122 million for 2004 year-to-date and $23 million for the third quarter. The three major factors driving the year-to-date decline are decreased revenues associated with establishing regulatory assets in Texas and the provision for refunds of fuel charges, offset in part by the cessation of deprecation on plants held for sale. The major factors driving the decline for the quarter are decreased revenues associated with establishing regulatory assets in Texas offset in part by the cessation of deprecation on plants held for sale and increased delivery revenues. The sale of several of our generation plants in July 2004 affected numerous line items on the income statement.

Third Quarter 2004 Compared to Third Quarter 2003

Operating Income

Operating Income for the three months ended September 30, 2004 decreased $17 million from the prior year period primarily due to:

o A $61 million decrease in revenues associated with establishing regulatory assets in Texas in 2003 (see "Texas Restructuring" in Note 4). These revenues did not continue after 2003.
o A $60 million decrease in Reliability Must Run (RMR) revenues from ERCOT. This amount includes both a fixed cost component decrease of $7 million and a fuel recovery decrease of $53 million primarily due to the sale of certain generation plants.
o A $22 million decrease in system sales, including those to Retail Electric Providers (REP), primarily due to lower KWH sales of 32%. The lower KWH sales are due to customer choice in Texas and the sale of certain generation plants.
o A $3 million decrease in margins resulting from risk management activities.
o A $3 million increase in Other Operation expenses primarily due to a $5 million increase of ERCOT-related transmission expenses and affiliated ancillary services and $3 million in customer-related expenses. These increases were partially offset by decreased production expenses primarily due to the sale of certain generation plants.

The decrease in Operating Income for the third quarter of 2004 was partially offset by:

o A $91 million net decrease in fuel and purchased power expenses. KWHs purchased decreased 9% while the per unit cost increased 18%. Although the KWHs generated decreased 57%, generating costs decreased 91% attributable mostly to the sale of certain generation units.
o A $13 million decrease in Depreciation and Amortization expenses primarily due to the cessation of depreciation on plants classified as held for sale (see Note 7 "Dispositions and Assets Held for Sale").
o A $9 million increase in retail delivery revenues primarily driven by an increase in cooling degree-days of 5%.
o A $7 million decrease in Income Taxes. See Income Taxes section below for further discussion.
o A $4 million decrease in Maintenance expenses primarily due to the sale of certain generation plants.
o A $3 million increase in other electric revenue primarily due to Qualified Scheduling Entity (QSE) fees, rent from electric property and miscellaneous service revenue.

Other Impacts on Earnings

Nonoperating Income decreased $18 million primarily as a result of risk management activities.

Interest Charges decreased $4 million primarily due to the defeasance of $112 million of First Mortgage Bonds, the deferral of the interest cost as a regulatory asset related to the cost of the sale of certain generation assets, redemption of the 8% Notes Payable to Trust and other financing activities.

Income Taxes

The effective tax rates for the third quarter of 2004 and 2003 were 28.0% and 32.0% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower pre-tax income in 2004 and consolidated tax savings from parent.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Operating Income

Operating Income for the nine months ended September 30, 2004 decreased $126 million from the prior year period primarily due to:

o A $188 million decrease in system sales, including those to REPs, primarily due to lower KWH sales of 33%. The decrease in KWH sales is due to customer choice in Texas and the sale of certain generation plants. There was also a small decrease in the overall average price per KWH.
o A $169 million decrease in revenues associated with establishing regulatory assets in Texas in 2003 (see "Texas Restructuring" in Note 4).
o A $69 million decrease in RMR revenues from ERCOT which includes both a fuel recovery decrease of $61 million and a fixed cost component decrease of $8 million.
o A $22 million increase in provisions for rate refunds due to fuel reconciliation issues (see "TCC Fuel Reconciliation" in Note 3).
o A $20 million increase in Other Operation expenses primarily due to $13 million increase of ERCOT-related transmission expense and affiliated ancillary services; $1 million increase in production expenses including emission allowances; $3 million increase in customer related expenses; and a $3 million increase in administrative and support expenses.
o An $18 million decrease in margins from risk management activities.
o A $13 million decrease in retail delivery revenues driven by a decrease in KWH of 1% due in large part to a decrease in heating and cooling degree-days of 7%.
o A $6 million decrease in QSE fees primarily due to one REP not using TCC as their QSE in 2004.
o A $3 million decrease in revenues from ERCOT for various services including balancing energy.
o A $2 million increase in Taxes Other Than Income Taxes primarily due to an increase of $3 million related to property taxes attributable to changes in property values, property tax rates, net fixed asset decreases - which includes the sale of certain generation plants, accrual update adjustments and timing of prior period adjustments offset in part by lower franchise taxes of $1 million.

The decrease in Operating Income was partially offset by:

o A $254 million net decrease in fuel and purchased power expenses. KWHs purchased decreased 59% while the per unit cost increased 17%. Per unit generation costs decreased 25% and KWHs generated decreased 11% due to the sale of certain generation plants.
o A $68 million decrease in Income Taxes. See Income Taxes section below for further discussion.
o A $55 million decrease in Depreciation and Amortization expenses primarily due to the cessation of depreciation on plants classified as held for sale (see Note 7 "Dispositions and Assets Held for Sale").
o A $13 million increase in transmission revenue primarily due to affiliated OATT (including a $7.6 million true-up for prior years recorded in 2004) and ancillary services.
o A $3 million decrease in Maintenance expenses primarily due to the sale of certain generation plants.

Other Impacts on Earnings

Nonoperating Income decreased $12 million primarily as a result of risk management activities of $9 million and $6 million in lower non-utility revenues associated with energy-related construction projects for third parties offset in part by a $2 million increase attributed to higher allowance for funds used during construction and interest income.

Nonoperating Expenses decreased $3 million primarily due to lower non-utility expenses associated with energy-related construction projects for third parties.

Interest Charges decreased $6 million primarily due to the defeasance of $112 million of First Mortgage Bonds, the deferral of the interest cost as a regulatory asset related to the cost of the sale of generation assets, the redemption of the 8% Notes Payable to Trust and other financing activities.

Income Taxes

The effective tax rates for the first nine months of 2004 and 2003 were 24.3% and 33.6% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower pre-tax income in 2004 and consolidated tax savings from parent.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch

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First Mortgage Bonds	Baa1	BBB	A
Senior Unsecured Debt	Baa2	BBB	A-

Cash Flow

Cash flows for the nine months ended September 30, 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$760	$808
Cash flow from (used for):		
Operating activities	193,107	239,370
Investing activities	258,422	(49,653)
Financing activities	(450,529)	(187,220)
Net increase in cash and cash equivalents	1,000	2,497
Cash and cash equivalents at end of period	$1,760	$3,305

Operating Activities

Our cash flows from operating activities were $193 million for the first nine months of 2004. We produced income of $72 million during the period including noncash expense items of $93 million for depreciation, amortization and $(121) million for deferred income taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are an increase in the balance of taxes accrued of $147 million and a decrease in interest accrued of $20 million.

Investing Activities

Cash Flows From Investing Activities were $258 million in 2004 primarily due to proceeds from the sale of several of our generation plants offset in part by $72 million in construction expenditures and $118 million in cash deposits for future long-term debt retirement. For the remainder of 2004, we expect our Construction Expenditures to be approximately $63 million.

Financing Activities

Cash Flows Used for Financing Activities of $451 million in 2004 were due to retirements of long-term debt, payment of dividends and increased Advances to Affiliates.

Financing Activity

Long-term debt issuances, retirements and defeasance during the first nine months of 2004 were:

Issuances

None

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$ 6,195	6.625	2005
Securitization Bonds	48,551	3.540	2005
Notes Payable to Trust	140,889	8.00	2037

Defeasance

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$27,400	7.25	2004
First Mortgage Bonds	65,763	6.625	2005
First Mortgage Bonds	18,581	7.125	2008

Liquidity

We have solid investment grade ratings which provide us ready access to capital markets in order to refinance long-term debt maturities. In addition, we participate in the AEP Utility Money Pool, which provides access to the liquidity of the AEP System. Finally, we expect to receive asset sale proceeds of approximately $376 million in the first half of 2005. These proceeds may be used to reduce current portions of long-term debt outstanding.

Significant Factors

We made progress on our planned divestiture of all of our generation assets by
(1) announcing in June 2004 and September 2004 that we had signed agreements to sell our 7.81% share of the Oklaunion Power Station to two unaffiliated co-owners of the plant for approximately $43 million, subject to closing adjustments, (2) announcing in September 2004 that we had signed agreements to sell our 25.2% share of the South Texas Project nuclear plant to two unaffiliated co-owners of the plant for approximately $333 million, subject to closing adjustments, and (3) in July 2004 closing on the sale of our remaining generation assets, including eight natural gas plants, one coal-fired plant and one hydro plant for approximately $425 million, net of adjustments. We expect the sales of Oklaunion and South Texas Project to be completed in the first half of 2005. Nevertheless, there could be potential delays in receiving necessary regulatory approvals and clearances, which could delay the closings. We will file with the Public Utility Commission of Texas to recover net stranded costs associated with the sales pursuant to Texas restructuring

legislation. Stranded costs will be calculated on the basis of all generation assets not individual plants.

Nuclear Decommissioning

As discussed in the 2003 Annual Report, decommissioning costs are accrued over the service life of STP. The licenses to operate the two nuclear units at STP expire in 2027 and 2028. TCC had estimated its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year.

In May 2004, an updated decommissioning study was completed for STP. The study estimates TCC's share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. We are currently analyzing the STP study to determine the effect on our asset retirement obligations (ARO) and will make any appropriate adjustments to the ARO liability and related regulatory asset in the fourth quarter 2004. As discussed in Note 7, TCC is in the process of selling its ownership interest in STP to a non-affiliate, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report 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

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

MTM Risk Management Contract Net Liabilities

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

MTM Risk Management Contract Net Liabilities
Nine Months Ended September 30, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$11,942
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(4,555)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(98)
Change in Fair Value Due to Valuation Methodology Changes (d)	110
Changes in Fair Value of Risk Management Contracts (e)	552
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	7,951
Net Cash Flow Hedge Contracts (g)	(10,832)
Total MTM Risk Management Contract Net Liabilities at September 30, 2004	$(2,881)

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changing methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to

Consolidated Balance Sheets
As of September 30, 2004

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Consolidated (b)
	(in thousands)		
Current Assets	$17,277	$193	$17,470
Non Current Assets	8,373	59	8,432
Total MTM Derivative Contract Assets	25,650	252	25,902
Current Liabilities	(13,774)	(10,684)	(24,458)
Non Current Liabilities	(3,925)	(400)	(4,325)
Total MTM Derivative Contract Liabilities	(17,699)	(11,084)	(28,783)
Total MTM Derivative Contract Net Assets (Liabilities)	$7,951	$(10,832)	$(2,881)

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

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

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

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, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$618	$(1,849)	$8	$585	$-	$-	$(638)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(2,381)	4,313	385	-	-	-	2,317
Prices Based on Models and Other Valuation Methods (b)	2,496	891	186	(49)	672	2,076	6,272
Total	$733	$3,355	$579	$536	$672	$2,076	$7,951

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the- counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008, of which $813 thousand of this mark-to-market value is in 2009.
(d) Amounts exclude Cash Flow Hedges.

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

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

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

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Nine Months Ended September 30, 2004

(in thousands)	Power
Beginning Balance December 31, 2003	$(1,828)
Changes in Fair Value (a)	(6,134)
Reclassifications from AOCI to Net Income (b)	1,004
Ending Balance September 30, 2004	$(6,958)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges

during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $6,736 thousand loss.

Credit Risk

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

VaR Associated with Management Contracts

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

Nine Months Ended September 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$86	$479	$223	$78	$189	$733	$307	$73

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $131 million and $206 million at September 30, 2004 and December 31, 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$347,013	$443,578	$872,835	$1,264,757
Sales to AEP Affiliates	7,596	41,551	38,622	131,176
TOTAL	354,609	485,129	911,457	1,395,933
OPERATING EXPENSES				
Fuel for Electric Generation	6,967	24,475	50,879	73,244
Fuel from Affiliates for Electric Generation	1,707	72,776	101,883	155,976
Purchased Electricity for Resale	114,371	116,562	140,925	305,338
Purchased Electricity from AEP Affiliates	54	273	6,065	19,045
Other Operation	74,780	72,185	228,198	207,863
Maintenance	12,215	16,657	51,328	54,567
Depreciation and Amortization	34,884	48,158	92,860	148,105
Taxes Other Than Income Taxes	23,814	24,747	69,028	67,509
Income Taxes	18,027	24,794	23,645	91,171
TOTAL	286,819	400,627	764,811	1,122,818
OPERATING INCOME	67,790	84,502	146,646	273,115
Nonoperating Income	6,783	25,006	30,946	43,069
Nonoperating Expenses	3,628	3,647	11,384	14,479
Nonoperating Income Tax Expense (Credit)	(1,336)	6,319	(476)	7,117
Interest Charges	29,269	33,321	94,609	100,343
Income Before Cumulative Effect of Accounting Change	43,012	66,221	72,075	194,245
Cumulative Effect of Accounting Change (Net of Tax)	-	-	-	122
NET INCOME	43,012	66,221	72,075	194,367
Preferred Stock Dividend Requirements	60	60	181	181
EARNINGS APPLICABLE TO COMMON STOCK	$42,952	$66,161	$71,894	$194,186

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

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$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 (Loss), Net of Taxes:					
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
DECEMBER 31, 2003	$55,292	$132,606	$1,083,023	$(61,872)	$1,209,049
Common Stock Dividends			(148,000)		(148,000)
Preferred Stock Dividends			(181)		(181)
TOTAL					1,060,868
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(5,130)	(5,130)
Minimum Pension Liability				(3,471)	(3,471)
NET INCOME			72,075		72,075
TOTAL COMPREHENSIVE INCOME					63,474
SEPTEMBER 30, 2004	$55,292	$132,606	$1,006,917	$(70,473)	$1,124,342

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$-	$-
Transmission	782,006	767,970
Distribution	1,420,683	1,376,761
General	231,533	221,354
Construction Work in Progress	42,098	58,953
TOTAL	2,476,320	2,425,038
Accumulated Depreciation and Amortization	724,408	695,359
TOTAL - NET	1,751,912	1,729,679
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	1,584	1,302
Bond Defeasance Funds	21,945	-
Other Investments	-	4,639
TOTAL	23,529	5,941
CURRENT ASSETS		
Cash and Cash Equivalents	1,760	760
Other Cash Deposits	139,254	65,122
Advances to Affiliates	172,051	60,699
Accounts Receivable:		
Customers	140,184	146,630
Affiliated Companies	74,742	78,484
Accrued Unbilled Revenues	24,457	23,077
Allowance for Uncollectible Accounts	(3,406)	(1,710)
Materials and Supplies	12,557	11,708
Risk Management Assets	17,470	22,051
Margin Deposits	1,142	3,230
Prepayments and Other Current Assets	5,176	6,770
TOTAL	585,387	416,821
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	3,516	3,249
Wholesale Capacity Auction True-up	480,000	480,000
Unamortized Loss on Reacquired Debt	12,108	9,086
Designated for Securitization	1,273,912	1,259,714
Deferred Debt - Restructuring	11,952	12,015
Other	108,877	127,488
Securitized Transition Assets	656,556	689,399
Long-term Risk Management Assets	8,432	7,627
Deferred Charges	57,978	55,554
TOTAL	2,613,331	2,644,132
Assets Held for Sale - Texas Generation Plants	608,759	1,028,134
TOTAL ASSETS	$5,582,918	$5,824,707

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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
Retained Earnings	1,006,917	1,083,023
Accumulated Other Comprehensive Income (Loss)	(70,473)	(61,872)
Total Common Shareholder's Equity	1,124,342	1,209,049
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Total Shareholders' Equity	1,130,282	1,214,989
Long-term Debt	1,541,450	2,053,974
TOTAL	2,671,732	3,268,963
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	554,842	237,651
Accounts Payable:		
General	95,179	90,004
Affiliated Companies	62,686	74,209
Customer Deposits	6,289	1,517
Taxes Accrued	214,269	67,018
Interest Accrued	23,161	43,196
Risk Management Liabilities	24,458	17,888
Obligation Under Capital Leases	417	407
Other	17,254	23,248
TOTAL	998,555	555,138
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,126,802	1,244,912
Long-term Risk Management Liabilities	4,325	2,660
Regulatory Liabilities:		
Asset Removal Costs	102,996	95,415
Deferred Investment Tax Credits	108,809	112,479
Over Recovery of Fuel Costs	69,026	69,026
Retail Clawback	29,824	45,527
Other	41,196	56,984
Obligation Under Capital Leases	497	636
Deferred Credits and Other	196,857	144,833
TOTAL	1,680,332	1,772,472
Liabilities Held for Sale - Texas Generation Plants	232,299	228,134
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,582,918	$5,824,707

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$72,075	$194,367
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	-	(122)
Depreciation and Amortization	92,860	148,105
Deferred Income Taxes	(121,111)	36,386
Deferred Investment Tax Credits	(3,670)	(3,905)
Deferred Property Taxes	(5,996)	(10,050)
Mark-to-Market of Risk Management Contracts	3,991	(13,426)
Wholesale Capacity Auction True-up	-	(169,000)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	10,504	(52,502)
Fuel, Materials and Supplies	(7,494)	17,060
Accounts Payable, Net	(6,348)	71,815
Taxes Accrued	147,251	24,043
Interest Accrued	(20,035)	(26,738)
Change in Other Assets	(2,572)	13,562
Change in Other Liabilities	33,652	9,775
Net Cash Flows From Operating Activities	193,107	239,370
INVESTING ACTIVITIES		
Construction Expenditures	(72,341)	(95,425)
Proceeds from Sale of Property and Other Assets	426,566	-
Change in Other Cash Deposits, Net	(74,132)	45,165
Change in Bond Defeasance Funds and Other	(21,671)	607
Net Cash Flows From (Used For) Investing Activities	258,422	(49,653)
FINANCING ACTIVITIES		
Change in Short-term Debt - Affiliates	-	(650,000)
Issuance of Long-term Debt	-	792,027
Retirement of Long-term Debt	(190,996)	(85,427)
Change in Advances to Affiliates	(111,352)	(153,038)
Dividends Paid on Common Stock	(148,000)	(90,601)
Dividends Paid on Cumulative Preferred Stock	(181)	(181)
Net Cash Flows Used For Financing Activities	(450,529)	(187,220)
Net Increase in Cash and Cash Equivalents	1,000	2,497
Cash and Cash Equivalents at Beginning of Period	760	808
Cash and Cash Equivalents at End of Period	$1,760	$3,305

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $108,791,000 and $117,427,000 and for income taxes was $(1,058,000) and $42,901,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries.

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

The notes to TCC's consolidated financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to TCC.

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

Results of Operations

Net Income decreased $7 million for 2004 year-to-date and $0.5 million for the third quarter. The year-to-date decrease was primarily driven by lower margins from risk management activities and a 2003 Cumulative Effect of Accounting Changes.

Third Quarter 2004 Compared to Third Quarter 2003

Operating Income

Operating Income for the three months ended September 30, 2004 increased $4 million from the prior year period primarily due to:

o A $30 million increase in system sales, including those to Retail Electric Providers (REP), primarily due to higher KWH sales of 53%.
o A $5 million increase in revenues from ERCOT for various services, including balancing energy and prior year's adjustments made by ERCOT recorded in 2003 and 2004.
o A $2 million increase in margins from risk management activities.
o A $2 million increase in transmission revenue primarily due to affiliated ancillary services.

The increase in Operating Income was partially offset by:

o A $29 million net increase in fuel and purchased power expenses. KWH generation decreased 6% while the generation cost per KWH increased 20% primarily due to increases in the price of natural gas. KWH's purchased increased 137% and the average cost per KWH purchased increased 6%.
o A $2 million increase in Depreciation and Amortization expenses resulting mainly from the prior year adjustment to the excess earnings accruals related to Texas Legislation (see "Texas Restructuring" in Note 4).
o A $1 million decrease in Reliability Must Run (RMR) revenues from ERCOT which includes a fuel recovery component and a fixed cost component.
o A $1 million increase in Taxes Other Than Income Taxes primarily due to higher accrued property taxes attributable to changes in property values, property tax rates, net fixed asset increases, accrual update adjustments and timing of prior period adjustments.

Other Impacts on Earnings

Nonoperating Income decreased $15 million as a result of a $9 million decrease in non-utility revenues associated with energy-related construction projects for third parties and a $6 million decrease related to risk management activities.

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

Income Taxes
The effective tax rates for the third quarter of 2004 and 2003 were 33.1% and 36.8% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower state income taxes and federal income tax return adjustments.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Operating Income

Operating Income for the nine months ended September 30, 2004 decreased $1 million from the prior year period primarily due to:

o A $14 million decrease in system sales, including those to REPs, primarily due to both lower KWH sales of 2% due to customer choice in Texas and a small decrease in the overall average price per KWH.
o A $7 million decrease in margins from risk management activities.
o A $5 million decrease in other electric revenue primarily due to Qualified Scheduling Entity fees and miscellaneous service revenue.
o A $3 million increase in Depreciation and Amortization expenses primarily due to the prior year adjustment for excess earnings accruals related to the Texas Legislation (see "Texas Restructuring" in Note 4).
o A $2 million decrease in retail delivery revenues due partly to a 16% decline in heating and cooling degree-days.
o A $2 million increase in Taxes Other Than Income Taxes primarily due to higher accrued property taxes attributable to changes in property values, property tax rates, net fixed asset increases, accrual update adjustments and timing of prior period adjustments.
o A $1 million increase in provision for rate refunds due to fuel reconciliation issues in 2003 (see "TNC Fuel Reconciliation" in Note 3).

The decrease in Operating Income was partially offset by:

o A $7 million net decrease in fuel and purchased power expenses. KWH's purchased increased 7% while the average cost per KWH purchased decreased 25%. KWH generation increased 1% while the generation cost per KWH increased 12% primarily due to increases in the price of natural gas.
o A $10 million increase in transmission revenue primarily due to prior year adjustments recorded in 2004 for affiliated OATT and ancillary services resulting from revised data received from ERCOT for the years 2001-2003.
o A $5 million decrease in Income Taxes. See Income Taxes section below for further discussion.
o A $4 million increase in revenues from ERCOT for various services, including balancing energy and prior year adjustments made by ERCOT and recorded in 2003 and 2004.
o A $3 million increase in RMR revenues from ERCOT which include a fuel recovery increase of $6 million and a fixed cost decrease of $3 million.
o A $3 million decrease in Other Operation expenses primarily due to proceeds of $1 million for the sale of emission allowances; decreased production expenses of approximately $1 million due to the elimination of the RMR status for the San Angelo Power Station - Unit 1; decreased transmission related expenses of $2 million offset in part by increased employee-related expenses.
o A $1 million increase in wholesale revenues due to higher fuel revenue which is part of average fuel cost pricing.

Other Impacts on Earnings

Nonoperating Income decreased $17 million primarily as a result of a $14 million decrease in non-utility revenue associated with energy-related construction projects for third parties and a decrease of $3 million related to risk management activities.

Nonoperating Expenses decreased $13 million primarily due to lower non-utility expenses associated with energy-related construction projects for third parties.

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

Income Taxes

The effective tax rates for the first nine months of 2004 and 2003 were 33.4% and 37.0% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower state income taxes and federal income tax return adjustments.

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-

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2004 were:

Issuances

None.

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$24,036	6.125	2004

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report 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

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

MTM Risk Management Contract Net Liabilities

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

MTM Risk Management Contract Net Liabilities
Nine Months Ended September 30, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$4,620
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(1,728)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(43)
Change in Fair Value Due to Valuation Methodology Changes (d)	45
Changes in Fair Value of Risk Management Contracts (e)	408
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
	-------
Total MTM Risk Management Contract Net Assets	

3,302
Net Cash Flow Hedge Contracts (g)
(3,770)

Total MTM Risk Management Contract Net Liabilities at September 30, 2004
$(468)

=======

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changing methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to Balance Sheets As of September 30, 2004

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
		(in thousands)	
Current Assets	$7,221	$83	$7,304
Non Current Assets	3,619	25	3,644
Total MTM Derivative Contract Assets	10,840	108	10,948
Current Liabilities	(5,842)	(3,705)	(9,547)
Non Current Liabilities	(1,696)	(173)	(1,869)
Total MTM Derivative Contract Liabilities	(7,538)	(3,878)	(11,416)
Total MTM Derivative Contract Net Assets (Liabilities)	$3,302	$(3,770)	$(468)

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

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

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

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, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008(c)	Total (d)
			(in thousands)				
Prices Actually Quoted - Exchange Traded Contracts	$267	$(799)	$3	$253	$-	$-	$(276)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(918)	1,864	166	-	-	-	1,112
Prices Based on Models and Other Valuation Methods (b)	835	385	80	(21)	290	897	2,466
Total	$184	$1,450	$249	$232	$290	$897	$3,302

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008, of which $351 thousand of this mark-to-market value is in 2009.
(d) Amounts exclude Cash Flow Hedges.

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

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

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

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Nine Months Ended September 30, 2004

	Power
	(in thousands)
Beginning Balance December 31, 2003	$(601)
Changes in Fair Value (a)	(2,140)
Reclassifications from AOCI to Net Income (b)	320
Ending Balance September 30, 2004	$(2,421)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2,326 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts
The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Nine Months Ended September 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$37	$207	$96	$34	$76	$294	$123	$29

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $13 million and $33 million at September 30, 2004 and December 31, 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore, a near term change in interest rates should not negatively affect our results of operation or financial position.

AEP TEXAS NORTH COMPANY
STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$139,905	$104,104	$317,585	$320,733
Sales to AEP Affiliates	12,599	10,351	39,344	46,790
TOTAL	152,504	114,455	356,929	367,523
OPERATING EXPENSES				
Fuel for Electric Generation	11,357	9,457	29,518	29,196
Fuel from Affiliates for Electric Generation	15,497	14,390	39,263	31,392
Purchased Electricity for Resale	51,517	22,933	92,822	74,434
Purchased Electricity from AEP Affiliates	309	2,486	4,385	38,280
Other Operation	23,213	23,394	63,150	66,378
Maintenance	4,544	4,552	15,177	14,705
Depreciation and Amortization	9,448	7,132	28,994	26,387
Taxes Other Than Income Taxes	6,476	5,281	16,873	14,746
Income Taxes	8,248	7,411	16,730	21,478
TOTAL	130,609	97,036	306,912	316,996
OPERATING INCOME	21,895	17,419	50,017	50,527
Nonoperating Income	8,637	23,572	38,025	54,877
Nonoperating Expenses	8,230	15,211	31,128	43,892
Nonoperating Income Tax Expense	83	2,707	2,186	3,188
Interest Charges	5,366	5,726	17,028	16,290
Income Before Cumulative Effect of Accounting Changes	16,853	17,347	37,700	42,034
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	-	3,071
NET INCOME	16,853	17,347	37,700	45,105
Preferred Stock Dividend Requirements	26	26	78	78
EARNINGS APPLICABLE TO COMMON STOCK	$16,827	$17,321	$37,622	$45,027

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

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$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:					
Cash Flow Hedges				130	130
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
DECEMBER 31, 2003	$137,214	$2,351	$125,428	$(26,718)	$238,275
Common Stock Dividends			(2,000)		(2,000)
Preferred Stock Dividends			(78)		(78)
TOTAL					236,197
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(1,820)	(1,820)
NET INCOME			37,700		37,700
TOTAL COMPREHENSIVE INCOME					35,880
SEPTEMBER 30, 2004	$137,214	$2,351	$161,050	$(28,538)	$272,077

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$362,115	$360,463
Transmission	278,017	268,695
Distribution	469,891	456,278
General	120,781	117,792
Construction Work in Progress	25,669	30,199
TOTAL	1,256,473	1,233,427
Accumulated Depreciation and Amortization	479,764	460,513
TOTAL - NET	776,709	772,914
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	1,164	1,286
CURRENT ASSETS		
Cash and Cash Equivalents	146	-
Other Cash Deposits	2,597	2,863
Advances to Affiliates	54,495	41,593
Accounts Receivable:		
Customers	69,684	56,670
Affiliated Companies	27,961	28,910
Accrued Unbilled Revenues	3,611	4,871
Miscellaneous	546	3,411
Allowance for Uncollectible Accounts	(770)	(175)
Fuel Inventory	7,052	10,925
Materials and Supplies	8,298	8,866
Risk Management Assets	7,304	10,340
Margin Deposits	494	1,285
Prepayments and Other	1,666	1,834
TOTAL	183,084	171,393
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Under Recovery of Fuel Costs	26,680	26,680
Deferred Debt - Restructuring	6,214	6,579
Unamortized Loss on Reacquired Debt	2,489	3,929
Other	2,757	3,332
Long-term Risk Management Assets	3,644	3,106
Deferred Charges	37,457	20,290
TOTAL	79,241	63,916
TOTAL ASSETS	$1,040,198	$1,009,509

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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
Retained Earnings	161,050	125,428
Accumulated Other Comprehensive Income (Loss)	(28,538)	(26,718)
Total Common Shareholder's Equity	272,077	238,275
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357
Total Shareholders' Equity	274,434	240,632
Long-term Debt	314,333	314,249
TOTAL	588,767	554,881
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	18,469	42,505
Accounts Payable:		
General	22,846	28,190
Affiliated Companies	41,952	40,601
Customer Deposits	1,503	161
Taxes Accrued	39,756	22,877
Interest Accrued	4,076	6,038
Risk Management Liabilities	9,547	8,658
Obligations Under Capital Leases	198	203
Other	7,162	9,419
TOTAL	145,509	158,652
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	113,021	113,019
Long-term Risk Management Liabilities	1,869	1,094
Regulatory Liabilities:		
Asset Removal Costs	80,233	76,740
Deferred Investment Tax Credits	19,016	19,990
Retail Clawback	6,837	11,804
Excess Earnings	13,394	14,262
SFAS 109 Regulatory Liability, Net	12,431	13,655
Other	1,668	1,826
Obligations Under Capital Leases	260	270
Deferred Credits and Other	57,193	43,316
TOTAL	305,922	295,976
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,040,198	$1,009,509

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$37,700	$45,105
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(3,071)
Depreciation and Amortization	28,994	26,387
Deferred Income Taxes	(1,980)	231
Deferred Investment Tax Credits	(974)	(1,140)
Deferred Property Taxes	(4,023)	(3,323)
Mark-to-Market of Risk Management Contracts	1,318	(4,786)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(7,345)	10,804
Fuel, Materials and Supplies	4,441	2,658
Accounts Payable, Net	(3,993)	(40,548)
Taxes Accrued	16,879	8,072
Change in Other Assets	(15,653)	(11,412)
Change in Other Liabilities	10,350	8,172
Net Cash Flows From Operating Activities	65,714	37,149
INVESTING ACTIVITIES		
Construction Expenditures	(27,328)	(33,136)
Change in Other Cash Deposits, Net	266	(1,442)
Other	510	595
Net Cash Flows Used For Investing Activities	(26,552)	(33,983)
FINANCING ACTIVITIES		
Change in Short-term Debt - Affiliates	-	(125,000)
Issuance of Long-term Debt	-	222,455
Retirement of Long-term Debt	(24,036)	-
Retirement - Preferred Stock	-	(10)
Change in Advances to Affiliates	(12,902)	(95,482)
Dividends Paid on Common Stock	(2,000)	(4,970)
Dividends Paid on Cumulative Preferred Stock	(78)	(78)
Net Cash Flows Used For Financing Activities	(39,016)	(3,085)
Net Increase in Cash and Cash Equivalents	146	81
Cash and Cash Equivalents at Beginning of Period	-	62
Cash and Cash Equivalents at End of Period	$146	$143

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $17,290,000 and $12,990,000 and for income taxes was $6,905,000 and $16,410,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries.

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

The notes to TNC's financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to TNC.

Results of Operations

Net Income for the third quarter of 2004 decreased $7 million from the prior year period primarily due to increases in Other Operation and Maintenance expenses coupled with a decrease in Nonoperating Income related to unfavorable results from risk management activities. The unfavorable impacts in Net Income were partially offset by decreased Income Taxes.

Net Income for the nine months ended September 30, 2004 decreased $91 million from the prior year period primarily due to the Cumulative Effect of Accounting Changes of $77 million recorded in 2003. In addition, increases in Other Operation, Maintenance and Depreciation and Amortization expenses were partially offset by decreased Interest Charges and increased Nonoperating Income related to favorable results from risk management activities.

Third Quarter 2004 Compared to Third Quarter 2003

Operating Income

Operating Income for the third quarter of 2004 decreased $4 million from the prior year period primarily due to:

o A $7 million increase in Other Operation expense primarily due to increased administrative and support expenses and increased insurance premiums partially offset by reduced employee-related benefits costs in 2004.
o A $4 million increase in Maintenance expense caused by boiler plant maintenance at Amos, Glen Lyn, Mountaineer and Sporn plants in 2004.
o A net $3 million increase in fuel and purchased electricity expenses including a $5 million increase in Fuel for Electric Generation expense partially offset by decreased purchased electricity expenses. The $5 million increase in Fuel for Electric Generation expense was primarily due to increased cost of coal consumed partially offset by decreases in deferred fuel expense and coal pile inventory survey adjustments.
o A $2 million increase in Depreciation and Amortization expense relating to a greater depreciable base in 2004 including the addition of capitalized software costs partially offset by reduced amortization for Virginia's transition generation regulatory assets. The reduced amortization is related to the extension of the transition period for electricity restructuring.

The decrease in Operating Income for the third quarter of 2004 was partially offset by:

o An $8 million decrease in Income Taxes. See Income Taxes section below for further discussion.
o A $4 million increase in Sales to AEP Affiliates reflecting a higher average price in MWH.

Other Impacts on Earnings

Nonoperating Income decreased $7 million in the third quarter of 2004 compared to the prior year period primarily due to unfavorable results from risk management activities.

Nonoperating Expenses decreased $2 million in the third quarter of 2004 compared to the prior year period due to a charitable donation in 2003 and decreased expenses of inactive coal companies.

Interest charges decreased $1 million in the third quarter of 2004 compared to the prior year period due to reduced interest rates from refinancing higher cost debt.

Income Taxes

The effective tax rates for the third quarter of 2004 and 2003 were 29.6% and 35.4%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to federal income tax return adjustments.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Operating Income

Operating Income for the nine months ended September 30, 2004 in comparison to the prior year period decreased $33 million primarily due to:

o A $29 million increase in Maintenance expenses caused by boiler plant maintenance at Amos, Clinch River, Glen Lyn and Kanawha River plants.
o A $17 million increase in Other Operation expenses primarily due to increased administrative and support expenses, increased insurance premiums and increased removal costs. These increases were partially offset by reduced labor costs in 2004.
o A $15 million increase in Depreciation and Amortization expense primarily due to reduced expense in 2003 attributable to the adoption of SFAS 143 for regulated operations and to a lesser degree, a greater depreciable base in 2004, which included the addition of capitalized software costs partially offset by reduced amortization of Virginia's transition generation regulatory assets. The reduced amortization is related to the extension of the transition period for electricity restructuring.
o A $4 million decrease in Sales to AEP Affiliates relating to decreased power available for sale caused by planned plant outages in 2004.

The decrease in Operating Income for the nine months ended September 30, 2004 was partially offset by:

o A $17 million increase in Electric Generation, Transmission and Distribution revenues primarily resulting from a 28% increase in cooling degree days in 2004 in comparison to the prior year period.
o A $10 million decrease in Income Taxes. See Income Taxes section below for further discussion.
o A net $4 million decrease in fuel and purchased electricity expenses including a $19 million decrease in Fuel for Electric Generation expenses partially offset by a $15 million increase in purchased electricity expenses. The decrease in Fuel for Electric Generation expenses was primarily due to decreased generation and deferred fuel expense partially offset by the increased cost of coal used in generation. Purchased electricity expenses increased due to lower generation caused by planned outages partially offset by decreased capacity charges.

Other Impacts on Earnings

Nonoperating Income increased $6 million in the nine months ended September 30, 2004 compared to the prior year period primarily due to favorable results from risk management activities.

Nonoperating Expenses decreased $3 million in the nine months ended September 30, 2004 compared to the prior year period due to decreased expenses of inactive coal companies.

Nonoperating Income Tax Credit decreased $4 million. See Income Taxes section below for further discussion.

Interest Charges decreased $13 million in the nine months ended September 30, 2004 compared to the prior year period due to reduced interest rates from refinancing higher cost debt and increased construction-related capitalized interest.

Income Taxes

The effective tax rates for the first nine months of 2004 and 2003 were 37.3% and 36.7%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes of $77 million is due to the implementation of SFAS 143 and EITF 02-3 in 2003.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the nine months ended September 30, 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$4,561	$4,133
Cash flow from (used for):		
Operating activities	397,919	409,707
Investing activities	(261,198)	(187,977)
Financing activities	(137,784)	(220,755)
Net increase (decrease) in cash and cash equivalents	(1,063)	975
Cash and cash equivalents at end of period	$3,498	$5,108

Operating Activities

Net Cash Flows From Operating Activities for the nine months ended September 30, 2004 were $398 million. We produced income of $126 million that included noncash expense items of $191 million for depreciation, amortization and deferred taxes. The other changes in assets and liabilities primarily represent items that had a current period cash flow impact such as changes in working capital, the largest of which were affiliated accounts receivable.

Investing Activities

Net Cash Flows Used For Investing Activities for the nine months ended September 30, 2004 were $261 million. Current year construction expenditures of $305 million were focused primarily on projects to improve service reliability for transmission and distribution, as well as environmental upgrades. In addition, Changes in Other Cash Deposits, Net of $41 million consisted primarily of monies set aside in 2003 for the retirement of the Installment Purchase Contracts in 2004. For the remainder of 2004, we expect our Construction Expenditures to be approximately $105 million.

Financing Activities

For the nine months ended September 30, 2004, we issued $126 million of Senior Unsecured Notes and we retired $66 million of First Mortgage Bonds and $40 million of Installment Purchase Contracts. In addition, we repaid $83 million of advances from affiliates and advanced $24 million to our affiliates and we paid $50 million in common dividends.

Liquidity

We have solid investment grade ratings which provide us ready access to capital markets in order to refinance long-term debt maturities. In addition, we participate in the AEP Utility Money Pool, which provides us access to liquidity of the AEP System.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2004 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$125,000	Variable	2007

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$45,000	7.125	2024
Installment Purchase Contracts	40,000	5.45	2019
First Mortgage Bonds	21,000	7.70	2004

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report 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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2004

	(in thousands)
Total MTM Risk Management Contract Net Assets at December 31, 2003	$68,066
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(32,269)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(345)
Change in Fair Value Due to Valuation Methodology Changes (d)	835
Changes in Fair Value of Risk Management Contracts (e)	4,229
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	2,907

Total MTM Risk Management Contract Net Assets	43,423
Net Cash Flow Hedge Contracts (g)	(21,364)
DETM Assignment (h)	(25,781)
Total MTM Risk Management Contract Net Liabilities at September 30, 2004	$(3,722)

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See Note 17 "Related Party Transactions" in the 2003 Annual Report.

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of September 30, 2004

	MTM Risk Management Contracts(a)	Cash Flow Hedges	DETM Assignment (b)	Consolidated (c)
		(in thousands)		
Current Assets	$87,524	$1,560	$-	$89,084
Non Current Assets	81,202	207	-	81,409
Total MTM Derivative Contract Assets	168,726	1,767	-	170,493
Current Liabilities	(80,289)	(21,485)	(10,624)	(112,398)
Non Current Liabilities	(45,014)	(1,646)	(15,157)	(61,817)
Total MTM Derivative Contract Liabilities	(125,303)	(23,131)	(25,781)	(174,215)
Total MTM Derivative Contract Net Assets (Liabilities)	$43,423	$(21,364)	$(25,781)	$(3,722)

(a) Does not include Cash Flow Hedges.

(b) See Note 17 "Related Party Transactions" in the 2003 Annual Report.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
		(in thousands)					
Prices Actively Quoted - Exchange Traded Contracts	$2,180	$(6,524)	$28	$2,066	$-	$-	$(2,250)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(3,024)	12,677	3,296	2,095	-	-	15,044
Prices Based on Models and Other Valuation Methods (b)	769	3,196	4,231	3,527	5,832	13,074	30,629
Total	$(75)	$9,349	$7,555	$7,688	$5,832	$13,074	$43,423

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008. $5.9 million of this mark-to-market value is in 2009 and $5.8 million of this mark-to-market is in 2010.
(d) Amounts exclude Cash Flow Hedges.

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

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

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

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2004

	Power	Foreign Currency	Interest Rate	Consolidated
		(in thousands)		
Beginning Balance December 31, 2003	$359	$(183)	$(1,745)	$(1,569)
Changes in Fair Value (a)	(2,658)	-	(10,622)	(13,280)
Reclassifications from AOCI to Net Income (b)	(1,363)	5	272	(1,086)
Ending Balance September 30, 2004	$(3,662)	$(178)	$(12,095)	$(15,935)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $3,876 thousand loss.

Credit Risk

Counterparty credit quality and exposure is generally consistent with that of **AEP.**

VaR Associated with Risk Management Contracts

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

Nine Months Ended September 30, 2004				Twelve Months Ended December 31, 2003			
(in thousands)				(in thousands)			
End	High	Average	Low	End	High	Average	Low
$304	$1,690	$786	$274	$596	$2,314	$969	$230

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $109 million and $102 million at September 30, 2004 and December 31, 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$428,689	$428,667	$1,314,647	$1,297,255
Sales to AEP Affiliates	58,726	54,944	163,655	167,335
TOTAL	487,415	483,611	1,478,302	1,464,590
OPERATING EXPENSES				
Fuel for Electric Generation	117,841	113,274	327,246	345,819
Purchased Electricity for Resale	19,727	18,365	54,157	50,745
Purchased Electricity from AEP Affiliates	90,257	92,857	268,537	257,382
Other Operation	70,725	64,065	209,393	192,806
Maintenance	36,240	31,855	130,493	101,420
Depreciation and Amortization	48,877	46,501	144,021	128,574
Taxes Other Than Income Taxes	22,995	23,232	69,947	70,583
Income Taxes	18,063	26,328	78,339	88,387
TOTAL	424,725	416,477	1,282,133	1,235,716
OPERATING INCOME	62,690	67,134	196,169	228,874
Nonoperating Income	636	7,502	9,336	2,878
Nonoperating Expenses	1,497	3,910	7,239	10,219
Nonoperating Income Tax Credit	(1,899)	(1,307)	(3,524)	(7,491)
Interest Charges	25,269	26,318	76,169	89,520
Income Before Cumulative Effect of Accounting Changes	38,459	45,715	125,621	139,504
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	-	77,257
NET INCOME	38,459	45,715	125,621	216,761
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	796	703	2,417	2,671
EARNINGS APPLICABLE TO COMMON STOCK	$37,663	$45,012	$123,204	$214,090

The common stock of APCo is wholly-owned by AEP.
See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$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 (Loss), Net of Taxes:					
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
DECEMBER 31, 2003	$260,458	$719,899	$408,718	$(52,088)	$1,336,987
Common Stock Dividends			(50,000)		(50,000)
Preferred Stock Dividends			(600)		(600)
Capital Stock Expense		1,817	(1,817)		-
TOTAL					1,286,387
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(14,366)	(14,366)
NET INCOME			125,621		125,621
TOTAL COMPREHENSIVE INCOME					111,255
SEPTEMBER 30, 2004	$260,458	$721,716	$481,922	$(66,454)	$1,397,642

See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,488,089	$2,287,043
Transmission	1,251,486	1,240,889
Distribution	2,051,936	2,006,329
General	307,207	294,786
Construction Work in Progress	302,750	311,884
TOTAL	6,401,468	6,140,931
Accumulated Depreciation and Amortization	2,413,097	2,321,360
TOTAL - NET	3,988,371	3,819,571
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	20,619	20,574
Other Investments	21,337	26,668
TOTAL	41,956	47,242
CURRENT ASSETS		
Cash and Cash Equivalents	3,498	4,561
Other Cash Deposits	707	41,320
Advances to Affiliates, Net	23,779	-
Accounts Receivable:		
Customers	125,478	133,717
Affiliated Companies	95,975	137,281
Accrued Unbilled Revenues	31,582	35,020
Miscellaneous	1,076	3,961
Allowance for Uncollectible Accounts	(5,951)	(2,085)
Fuel Inventory	48,511	42,806
Materials and Supplies	87,932	71,978
Risk Management Assets	89,084	71,189
Margin Deposits	5,421	11,525
Prepayments and Other	14,776	13,301
TOTAL	521,868	564,574
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Transition Regulatory Assets	26,528	30,855
SFAS 109 Regulatory Asset, Net	324,032	325,889
Unamortized Loss on Reacquired Debt	18,774	19,005
Other	41,512	41,447
Long-term Risk Management Assets	81,409	70,900
Deferred Property Taxes	20,769	35,343
Other Deferred Charges	23,552	22,185
TOTAL	536,576	545,624
TOTAL ASSETS	$5,088,771	$4,977,011

See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - No Par Value:		
Authorized - 30,000,000 Shares		
Outstanding - 13,499,500 Shares	$260,458	$260,458
Paid-in Capital	721,716	719,899
Retained Earnings	481,922	408,718
Accumulated Other Comprehensive Income (Loss)	(66,454)	(52,088)
Total Common Shareholder's Equity	1,397,642	1,336,987
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784
Total Shareholders' Equity	1,415,426	1,354,771
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	5,360	5,360
Long-term Debt	1,254,921	1,703,073
TOTAL	2,675,707	3,063,204
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	630,009	161,008
Advances from Affiliates, Net	-	82,994
Accounts Payable:		
General	132,417	140,497
Affiliated Companies	60,150	81,812
Customer Deposits	45,867	33,930
Taxes Accrued	80,616	50,259
Interest Accrued	38,820	22,113
Risk Management Liabilities	112,398	51,430
Obligations Under Capital Leases	7,179	9,218
Other	53,785	60,289
TOTAL	1,161,241	693,550
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	825,347	803,355
Regulatory Liabilities:		
Asset Removal Costs	98,139	92,497
Deferred Investment Tax Credits	31,546	30,545
Over-Recovery of Fuel Cost	65,036	68,704
Other Regulatory Liabilities	20,423	17,326
Long-term Risk Management Liabilities	61,817	54,327
Obligations Under Capital Leases	13,679	16,134
Asset Retirement Obligation	22,635	21,776
Deferred Credits and Other	113,201	115,593
TOTAL	1,251,823	1,220,257
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,088,771	$4,977,011

See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$125,621	$216,761
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(77,257)
Depreciation and Amortization	144,021	128,574
Deferred Income Taxes	31,596	3,394
Deferred Investment Tax Credits	1,001	(1,940)
Deferred Property Taxes	14,574	15,008
Deferred Power Supply Costs, Net	(3,668)	71,815
Mark to Market of Risk Management Contracts	18,137	33,727
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	59,734	68,673
Fuel, Materials and Supplies	(21,659)	6,202
Accounts Payable, Net	(29,742)	(57,931)
Customer Deposits	11,937	5,590
Taxes Accrued	30,357	18,001
Interest Accrued	16,707	20,354
Incentive Plan Accrued	(1,151)	(8,789)
Rate Stabilization Deferral	-	(75,601)
Change in Other Assets	3,294	6,162
Change in Other Liabilities	(2,840)	36,964
Net Cash Flows From Operating Activities	397,919	409,707
INVESTING ACTIVITIES		
Construction Expenditures	(305,055)	(190,047)
Proceeds from Sale of Property and Other	3,244	2,078
Change in Other Cash Deposits, Net	40,613	(8)
Net Cash Flows Used For Investing Activities	(261,198)	(187,977)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	125,595	495,122
Retirement of Long-term Debt	(106,006)	(545,237)
Change in Advances to/from Affiliates, Net	(106,773)	(73,639)
Dividends Paid on Common Stock	(50,000)	(96,200)
Dividends Paid on Cumulative Preferred Stock	(600)	(801)
Net Cash Flows Used For Financing Activities	(137,784)	(220,755)
Net Increase (Decrease) in Cash and Cash Equivalents	(1,063)	975
Cash and Cash Equivalents at Beginning of Period	4,561	4,133
Cash and Cash Equivalents at End of Period	$3,498	$5,108

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $53,622,000 and $63,481,000 and for income taxes was $(831,000) and $47,419,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to APCo's consolidated financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to APCo.

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

The decrease in Net Income of $10 million in third quarter 2004 was primarily due to decreases in operating revenues and nonoperating risk management activities.

The decrease in year-to-date Net Income of $29 million in 2004 was primarily due to a $27 million net-of-tax Cumulative Effect of Accounting Changes in the first quarter of 2003.

Third Quarter 2004 Compared to Third Quarter 2003

Operating Income

Operating Income decreased $6 million primarily due to:

o A $6 million decrease in retail electric revenues resulting from decreased weather-based demand from residential customers and decreased industrial sales due to a declining number of customers.
o A $3 million increase in Other Operation expenses primarily relating to lime expenses for pollution control and increases in steam power expenses and administrative and support expenses.
o A $3 million increase in Depreciation and Amortization expenses due to a greater depreciable base in 2004, including capitalized software costs and the increased amortization of transition generation regulatory assets due to normal operating adjustments.

The decrease in Operating Income was partially offset by:

o A $6 million decrease in Income Taxes expense. See Income Taxes section below for further discussion.

Other Impacts on Earnings

Nonoperating Income decreased $2 million due to unfavorable results from risk management activities.

Interest Charges increased $2 million due to the write-off of costs related to reacquired debt that was refinanced at lower interest rates.

Income Taxes

The effective tax rates for the third quarter of 2004 and 2003 were 31.5% and 32.7% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Operating Income

Operating Income decreased $5 million primarily due to:

o A $12 million decrease in non-affiliated wholesale energy sales due to lower sales volume and the expiration of municipal contracts.
o An $11 million increase in Other Operation expenses primarily relating to lime expenses for pollution control and increases in steam power expenses and administrative and support expenses.
o A $10 million increase in Depreciation and Amortization expenses due to a greater depreciable base in 2004, including capitalized software costs and the increased amortization of transition generation regulatory assets due to normal operating adjustments.
o A $7 million increase in fuel expenses due to higher coal costs.
o A $3 million increase in Maintenance expenses due primarily to boiler overhaul work from scheduled and forced outages.

The decrease in Operating Income was partially offset by:

o A $24 million increase in retail electric revenues resulting primarily from increased weather-related demand from residential and commercial customers during the second quarter 2004.
o A $9 million increase in operating revenues related to favorable results from risk management activities.
o A $6 million decrease in Income Taxes expense. See Income Taxes section below for further discussion.

Other Impacts on Earnings

Nonoperating Income increased $10 million due to favorable results from risk management activities.

Nonoperating Income Tax Credit decreased $5 million. See Income Taxes section below for further discussion.

Interest Charges increased $3 million due to the write-off of costs related to reacquired debt that was refinanced at lower interest rates.

Income Taxes

The effective tax rates for the first nine months of 2004 and 2003 were 33.6% and 33.4% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Changes

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

Financial Condition

Credit Ratings

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

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

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2004 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contracts	$43,695	Variable	2038
Installment Purchase Contracts	48,550	Variable	2038
Notes Payable - Affiliates	100,000	4.64	2010

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$11,000	7.60	2024
Installment Purchase Contracts	43,695	6.25	2020
Installment Purchase Contracts	48,550	6.375	2020

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report 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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$38,337
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(18,594)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(200)
Change in Fair Value Due to Valuation Methodology Changes (d)	898
Changes in Fair Value of Risk Management Contracts (e)	4,469
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	24,910
Net Cash Flow Hedge Contracts (g)	(3,273)
DETM Assignment (h)	(14,888)
Total MTM Risk Management Contract Net Assets at September 30, 2004	$6,749

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See Note 17 "Related Party Transactions" in the 2003 Annual Report.

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of September 30, 2004

	MTM Risk Management Contracts(a)	Cash Flow Hedges	DETM Assignment (b)	Consolidated (c)
	(in thousands)			
Current Assets	$50,378	$393	$-	$50,771
Non Current Assets	46,895	119	-	47,014
Total MTM Derivative Contract Assets	97,273	512	-	97,785
Current Liabilities	(46,368)	(2,969)	(6,135)	(55,472)
Non Current Liabilities	(25,995)	(816)	(8,753)	(35,564)
Total MTM Derivative Contract Liabilities	(72,363)	(3,785)	(14,888)	(91,036)
Total MTM Derivative Contract Net Assets (Liabilities)	$24,910	$(3,273)	$(14,888)	$6,749

(a) Does not include Cash Flow Hedges.
(b) See Note 17 "Related Party Transactions" in the 2003 Annual Report.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
		(in thousands)					
Prices Actively Quoted - Exchange Traded Contracts	$1,259	$(3,767)	$16	$1,193	$-	$-	$(1,299)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(1,746)	7,153	1,904	1,210	-	-	8,521
Prices Based on Models and Other Valuation Methods (b)	441	1,847	2,443	2,037	3,369	7,551	17,688
Total	$(46)	$5,233	$4,363	$4,440	$3,369	$7,551	$24,910

(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.
(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008. $3.4 million of this mark-to-market value is in 2009 and $3.3 million of this mark-to-market is in 2010.
(d) Amounts exclude Cash Flow Hedges.

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

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

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

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Nine Months Ended September 30, 2004

	Power
	(in thousands)
Beginning Balance December 31, 2003	$202
Changes in Fair Value (a)	(1,473)
Reclassifications from AOCI to Net Income (b)	(844)
Ending Balance September 30, 2004	$(2,115)

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

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,662 thousand loss.

Credit Risk

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

VaR Associated with Energy and Gas Risk Management Contracts

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

Nine Months Ended September 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$176	$976	$454	$158	$336	$1,303	$546	$130

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $78 million and $98 million at September 30, 2004 and December 31, 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$369,192	$375,936	$1,049,671	$1,027,732
Sales to AEP Affiliates	21,796	21,719	61,748	62,199
TOTAL	390,988	397,655	1,111,419	1,089,931
OPERATING EXPENSES				
Fuel for Electric Generation	49,732	42,473	142,528	127,937
Fuel From Affiliates for Electric Generation	-	7,882	10,603	18,485
Purchased Electricity for Resale	5,389	5,688	14,839	13,898
Purchased Electricity from AEP Affiliates	96,193	93,486	263,614	263,225
Other Operation	60,520	57,348	176,797	166,027
Maintenance	17,417	19,630	60,187	56,801
Depreciation and Amortization	37,933	34,442	111,196	101,478
Taxes Other Than Income Taxes	34,017	34,970	102,069	101,532
Income Taxes	24,525	30,543	65,187	70,787
TOTAL	325,726	326,462	947,020	920,170
OPERATING INCOME	65,262	71,193	164,399	169,761
Nonoperating Income (Loss)	1,808	3,778	7,656	(2,587)
Nonoperating Expenses	444	159	2,037	2,944
Nonoperating Income Tax Credit	383	84	92	5,231
Interest Charges	14,439	12,071	41,666	38,946
Income Before Cumulative Effect of Accounting Changes	52,570	62,825	128,444	130,515
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	-	27,283
NET INCOME	52,570	62,825	128,444	157,798
Preferred Stock - Capital Stock Expense	254	254	762	762
EARNINGS APPLICABLE TO COMMON STOCK	$52,316	$62,571	$127,682	$157,036

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

See Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$41,026	$575,384	$290,611	$(59,357)	$847,664
Common Stock Dividends Declared			(124,932)		(124,932)
Capital Stock Expense		762	(762)		-
TOTAL					722,732
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow 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
DECEMBER 31, 2003	$41,026	$576,400	$326,782	$(46,327)	$897,881
Common Stock Dividends Declared			(93,750)		(93,750)
Capital Stock Expense		762	(762)		-
TOTAL					804,131
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(2,317)	(2,317)
NET INCOME			128,444		128,444
TOTAL COMPREHENSIVE INCOME					126,127
SEPTEMBER 30, 2004	$41,026	$577,162	$360,714	$(48,644)	$930,258

See Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,652,487	$1,610,888
Transmission	431,021	425,512
Distribution	1,291,414	1,253,760
General	171,576	166,002
Construction Work in Progress	107,284	114,281
TOTAL	3,653,782	3,570,443
Accumulated Depreciation and Amortization	1,454,558	1,389,586
TOTAL - NET	2,199,224	2,180,857
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	22,309	22,417
Other Investments	6,065	8,663
TOTAL	28,374	31,080
CURRENT ASSETS		
Cash and Cash Equivalents	3,313	3,377
Other Cash Deposits	99	765
Advances to Affiliates	158,371	-
Accounts Receivable:		
Customers	39,945	47,099
Affiliated Companies	53,568	68,168
Accrued Unbilled Revenues	26,201	23,723
Miscellaneous	554	5,257
Allowance for Uncollectible Accounts	(794)	(531)
Fuel	27,423	14,365
Materials and Supplies	70,891	44,377
Risk Management Assets	50,771	40,095
Margin Deposits	3,185	6,636
Prepayments and Other	12,937	12,444
TOTAL	446,464	265,775
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Assets, Net	16,371	16,027
Transition Regulatory Assets	164,434	188,532
Unamortized Loss on Reacquired Debt	13,346	13,659
Other	30,227	24,966
Long-term Risk Management Assets	47,014	39,932
Deferred Property Taxes	15,750	62,262
Deferred Charges	17,469	15,276
TOTAL	304,611	360,654
TOTAL ASSETS	$2,978,673	$2,838,366

See Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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	577,162	576,400
Retained Earnings	360,714	326,782
Accumulated Other Comprehensive Income (Loss)	(48,644)	(46,327)
Total Common Shareholder's Equity	930,258	897,881
Long-term Debt:		
Nonaffiliated	887,560	886,564
Affiliated	100,000	-
Total Long-term Debt	987,560	886,564
TOTAL	1,917,818	1,784,445
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	-	11,000
Advances from Affiliates, Net	-	6,517
Accounts Payable:		
General	49,721	58,220
Affiliated Companies	46,536	53,572
Customer Deposits	26,412	19,727
Taxes Accrued	134,968	132,853
Interest Accrued	7,888	16,528
Risk Management Liabilities	55,472	28,966
Obligations Under Capital Leases	4,126	4,221
Other	22,555	25,364
TOTAL	347,678	356,968
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	467,804	458,498
Regulatory Liabilities:		
Asset Removal Costs	103,112	99,119
Deferred Investment Tax Credits	28,664	30,797
Long-term Risk Management Liabilities	35,564	30,598
Obligations Under Capital Leases	8,892	11,397
Asset Retirement Obligations	9,262	8,740
Deferred Credits and Other	59,879	57,804
TOTAL	713,177	696,953
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,978,673	$2,838,366

See Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$128,444	$157,798
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(27,283)
Depreciation and Amortization	111,196	101,478
Deferred Income Taxes	10,210	(3,942)
Deferred Investment Tax Credits	(2,133)	(2,288)
Deferred Property Taxes	46,512	46,478
Mark-to-Market of Risk Management Contracts	10,130	29,056
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	24,242	27,106
Fuel, Materials and Supplies	(39,572)	3,326
Accounts Payable	(15,535)	(74,407)
Taxes Accrued	2,115	(33,868)
Interest Accrued	(8,640)	(2,054)
Change in Other Assets	(6,865)	(12,532)
Change in Other Liabilities	9,225	(2,347)
Net Cash Flows From Operating Activities	269,329	206,521
INVESTING ACTIVITIES		
Construction Expenditures	(101,656)	(98,032)
Proceeds from Sale of Property and Other	3,423	190
Change in Other Cash Deposits, Net	666	16
Net Cash Flows Used For Investing Activities	(97,567)	(97,826)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	90,057	494,350
Issuance of Long-term Debt - Affiliated	100,000	-
Change in Advances to/from Affiliates, Net	(164,888)	182,832
Retirement of Long-term Debt - Nonaffiliated	(103,245)	(207,500)
Retirement of Long-term Debt - Affiliated	-	(160,000)
Change in Short-term Debt - Affiliates	-	(290,000)
Dividends Paid on Common Stock	(93,750)	(124,932)
Net Cash Flows Used For Financing Activities	(171,826)	(105,250)
Net Increase (Decrease) in Cash and Cash Equivalents	(64)	3,445
Cash and Cash Equivalents at Beginning of Period	3,377	697
Cash and Cash Equivalents at End of Period	$3,313	$4,142

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $46,034,000 and $39,804,000 and for income taxes was $(5,282,000) and $48,955,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to CSPCo's consolidated financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to CSPCo.

Results of Operations

Net Income increased $14 million for the third quarter of 2004 and $58 million for the first nine months of 2004. The increases in Net Income reflect improvement in retail sales, the end of amortization of Cook Plant outage settlements and reduced financing charges in both the quarter and year-to-date periods and favorable results from risk management activities for the year-to-date period.

Third Quarter 2004 Compared to Third Quarter 2003

Operating Income

Operating Income increased $11 million primarily due to:

o A $17 million increase in Electric Generation, Transmission and Distribution revenues primarily due to an increase in commercial and industrial sales reflecting the economic recovery and the end of amortization of Cook outage settlements.
o A $9 million decrease in Other Operation expenses reflecting the end of amortization of Cook Plant outage settlements.
o A $5 million decrease in Maintenance expenses primarily due to the end of amortization of Cook Plant outage settlements and decreased storm damage expenses.
o A $5 million decrease in Taxes Other Than Income Taxes primarily due to prior year accrual adjustments for Indiana real and personal property taxes related to reassessed property values and tax rates.
o A $3 million increase in Sales to AEP Affiliates reflecting increased availability of Cook Plant units.

The increase in Operating Income was partially offset by:

o A $13 million increase in Income Taxes. See Income Taxes section below for further discussion.
o A $7 million increase in Fuel for Electric Generation expenses due to increased generation and higher fuel costs.
o A $6 million increase in Purchased Electricity from AEP Affiliates reflecting increased generation and higher fuel costs for power acquired under an AEGCo unit power agreement.

Other Impacts on Earnings

Nonoperating Income Tax Expense decreased $2 million. See Income Taxes section below for further discussion.

Interest Charges decreased $3 million primarily due to a reduction in outstanding long-term debt and lower interest rates from refunding higher cost debt.

Income Taxes

The effective tax rates for the third quarter of 2004 and 2003 were 34.5% and 29.5% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The increase in the effective tax rate is primarily due to permanent differences related to tax-exempt interest income, offset by federal income tax return adjustments.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Operating Income

Operating Income increased $33 million primarily due to:

o A $44 million increase in Electric Generation, Transmission and Distribution revenues due to an increase in commercial and industrial sales reflecting the economic recovery and the end of amortization of Cook Plant outage settlements.
o A $13 million decrease in Other Operation expenses including the end of amortization of Cook Plant outage settlements.
o A $5 million decrease in Purchased Electricity from AEP Affiliates primarily due to an 8% increase in net generation that reduced our need to purchase power from affiliates.
o A $4 million decrease in Taxes Other Than Income Taxes primarily due to prior year accrual adjustments for Indiana real and personal property taxes related to reassessed property values and tax rates.
o A $2 million decrease in Fuel for Electric Generation expenses reflecting a change in fuel mix as nuclear generation increased 32% and coal-fired generation declined 12% due to generating unit availability.

The increase in Operating Income was partially offset by:

o A $26 million increase in Income Taxes. See Income Taxes section below for further discussion.
o A $6 million increase in Maintenance expenses primarily due to both planned and forced outages at Rockport and Tanners Creek plants, increased costs for distribution right of way, line maintenance and cost of storm damage.
o A $3 million decrease in Sales to AEP Affiliates due to lower capacity revenues partially offset by increased energy sales to our affiliates.

Other Impacts on Earnings

Nonoperating Income increased $18 million primarily due to favorable results from risk management activities and increased barging revenues.

Nonoperating Expenses increased $3 million primarily due to increased costs for barging activities.

Nonoperating Income Tax Expense increased $6 million. See Income Taxes section below for further discussion.

Interest Charges decreased $13 million primarily due to a reduction in outstanding long-term debt and lower interest rates from refunding higher cost debt.

Income Taxes

The effective tax rates for the first nine months of 2004 and 2003 were 36.1% and 35.5% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change is due to the implementation of the requirements of EITF 02-3 related to mark-to-market accounting for risk management contracts that are not derivatives.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

Cash Flow

Cash flows for the first nine months of 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$3,899	$3,251
Cash flow from (used for):		
Operating activities	407,169	191,018

Investing activities	(121,913)	(106,574)
Financing activities	(286,774)	(83,634)
Net increase (decrease) in cash and cash equivalents	(1,518)	810
Cash and cash equivalents at end of period	$2,381	$4,061

Operating Activities

Our cash flows from operating activities were $407 million for the first nine months of 2004. We produced income of $122 million during the period including noncash expense items of $126 million for depreciation, amortization and deferred income taxes. In addition, there is a current period impact for a net $11 million balance sheet change for risk management contracts that are marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are increases in the balance of fuel, materials and supplies of $20 million and the balance of accrued taxes of $55 million and a net change in accounts receivable and payable of $18 million.

Investing Activities

Cash Flows Used For Investing Activities during 2004 were $122 million due to construction expenditures. Construction expenditures for nuclear and coal generation, transmission and distribution assets were incurred to upgrade or replace equipment and improve reliability. For the remainder of 2004, we expect our Construction Expenditures to be approximately $49 million.

Financing Activities

During the first nine months of 2004, we used cash of $205 million to retire long-term debt and $79 million to pay common dividends. These activities were supported by the generation of $407 million in cash flow from operations.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2004 were:

Issuances

None.

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$30,000	7.20	2024
First Mortgage Bonds	25,000	7.50	2024
Senior Unsecured Notes	150,000	6.875	2004

We anticipate issuing long-term debt during the fourth quarter.

Off-Balance Sheet Arrangements

We enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our current policy restricts the use of off-balance sheet financing entities or structures, except for traditional operating lease arrangements and sales of customer accounts receivable that are entered in the normal course of business. Our off-balance sheet arrangements have not changed significantly since year-end. For complete information on our off-balance sheet arrangements see "Off-balance Sheet Arrangements" in "Management's Financial Discussion and Analysis" section of our 2003 Annual Report.

Spent Nuclear Fuel Disposal

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for spent nuclear fuel (SNF), we and South Texas Project Nuclear Operating Company, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, we filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. On January 17, 2003, the U.S. Court of Federal Claims ruled in our favor on the issue of liability. The case continued on the issue of damages owed to us by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against us and denied damages. In July 2004, we appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. As long as the delay in the availability of the government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase. If such cost increases are not recovered on a timely basis in regulated rates, future results of operations and cash flows could be adversely affected.

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report 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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$41,995
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(15,341)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(222)
Change in Fair Value Due to Valuation Methodology Changes	-

Changes in Fair Value of Risk Management Contracts (d)	2,215
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(761)
Total MTM Risk Management Contract Net Assets	27,886
Net Cash Flow Hedge Contracts (f)	(13,236)
DETM Assignment (g)	(16,583)
Total MTM Risk Management Contract Net Liabilities at September 30, 2004	$(1,933)

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(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) "Changes 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.
(f) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss). (g) See Note 17 "Related Party Transactions" in the 2003 Annual Report.

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of September 30, 2004

	MTM Risk Management Contracts (a)	Cash Flow Hedges	DETM Assignment (b)	Consolidated (c)
	(in thousands)			
Current Assets	$56,305	$696	$-	$57,001
Non Current Assets	52,232	133	-	52,365
Total MTM Derivative Contract Assets	108,537	829	-	109,366
Current Liabilities	(51,645)	(12,998)	(6,833)	(71,476)
Non Current Liabilities	(29,006)	(1,067)	(9,750)	(39,823)
Total MTM Derivative Contract Liabilities	(80,651)	(14,065)	(16,583)	(111,299)

Total MTM Derivative Contract Net Assets (Liabilities)	$27,886	$(13,236)	$(16,583)	$(1,933)
	========	=========	=========	=========

(a) Does not include Cash Flow Hedges.
(b) See Note 17 "Related Party Transactions" in the 2003 Annual Report.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:
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, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$1,402	$(4,196)	$18	$1,329	$-	$-	$(1,447)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(1,752)	7,967	2,120	1,348	-	-	9,683
Prices Based on Models and Other Valuation Methods (b)	441	2,056	2,721	2,269	3,752	8,411	19,650
Total	$91	$5,827	$4,859	$4,946	$3,752	$8,411	$27,886

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008. $3.8 million of this mark-to-market value is in 2009 and $3.7 million of this mark-to-market is in 2010.
(d) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Nine Months Ended September 30, 2004

	Power	Interest Rate	Consolidated
		(in thousands)	
Beginning Balance December 31, 2003	$222	$-	$222
Changes in Fair Value (a)	(1,650)	(6,188)	(7,838)
Reclassifications from AOCI to Net Income (b)	(927)	-	(927)
Ending Balance September 30, 2004	$(2,355)	$(6,188)	$(8,543)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2,393 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Nine Months Ended September 30, 2004				Twelve Months Ended December 31, 2003			
(in thousands)				(in thousands)			
End	High	Average	Low	End	High	Average	Low
$196	$1,087	$505	$176	$368	$1,429	$598	
$142							

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $89 million and $79 million at September 30, 2004 and December 31, 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$372,558	$356,003	$1,065,830	$1,022,296
Sales to AEP Affiliates	70,378	67,001	193,048	196,212
TOTAL	442,936	423,004	1,258,878	1,218,508
OPERATING EXPENSES				
Fuel for Electric Generation	75,086	67,588	204,709	206,445
Purchased Electricity for Resale	10,063	9,058	22,617	22,375
Purchased Electricity from AEP Affiliates	74,498	68,653	203,291	207,904
Other Operation	100,537	109,106	306,187	319,019
Maintenance	33,737	38,518	118,055	112,480
Depreciation and Amortization	43,170	43,453	128,581	130,020
Taxes Other Than Income Taxes	10,291	15,698	40,979	44,668
Income Taxes	28,072	14,688	67,169	41,136
TOTAL	375,454	366,762	1,091,588	1,084,047
OPERATING INCOME	67,482	56,242	167,290	134,461
Nonoperating Income	20,248	20,723	60,857	42,670
Nonoperating Expenses	20,754	19,518	52,936	50,395
Nonoperating Income Tax Expense (Credit)	(953)	821	1,538	(4,479)
Interest Charges	16,381	19,510	52,087	64,603
Net Income Before Cumulative Effect of Accounting Change	51,548	37,116	121,586	66,612
Cumulative Effect of Accounting Change (Net of Tax)	-	-	-	(3,160)
NET INCOME	51,548	37,116	121,586	63,452
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	119	118	356	2,390
EARNINGS APPLICABLE TO COMMON STOCK	$51,429	$36,998	$121,230	$61,062

The common stock of I&M is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$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 (Loss), Net of Taxes:					
Cash Flow 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
DECEMBER 31, 2003	$56,584	$858,694	$187,875	$(25,106)	$1,078,047
Common Stock Dividends			(79,293)		(79,293)
Preferred Stock Dividends			(255)		(255)
Capital Stock Expense		107	(101)		6
					998,505
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(8,765)	(8,765)
NET INCOME			121,586		121,586
TOTAL COMPREHENSIVE INCOME					112,821
SEPTEMBER 30, 2004	$56,584	$858,801	$229,812	$(33,871)	$1,111,326

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,963,158	$2,878,051
Transmission	1,005,455	1,000,926
Distribution	979,690	958,966
General (including nuclear fuel)	275,941	274,283
Construction Work in Progress	171,792	193,956
TOTAL	5,396,036	5,306,182
Accumulated Depreciation and Amortization	2,579,039	2,490,912
TOTAL - NET	2,816,997	2,815,270
OTHER PROPERTY AND INVESTMENTS		
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,029,112	982,394
Non-Utility Property, Net	50,480	52,303
Other Investments	29,499	43,797
TOTAL	1,109,091	1,078,494
CURRENT ASSETS		
Cash and Cash Equivalents	2,381	3,899
Other Cash Deposits	46	15
Accounts Receivable:		
Customers	52,841	63,084
Affiliated Companies	93,282	124,826
Miscellaneous	4,176	4,498
Allowance for Uncollectible Accounts	(46)	(531)
Fuel	31,350	33,968
Materials and Supplies	128,156	105,328
Risk Management Assets	57,001	44,071
Margin Deposits	3,529	7,245
Prepayments and Other	9,159	10,673
TOTAL	381,875	397,076
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	138,575	151,973
Incremental Nuclear Refueling Outage Expenses, Net	26,131	57,326
Other	69,489	66,978
Long-term Risk Management Assets	52,365	43,768
Deferred Property Taxes	11,896	21,916
Deferred Charges and Other Assets	35,674	26,270
TOTAL	334,130	368,231
TOTAL ASSETS	$4,642,093	$4,659,071

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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	858,801	858,694
Retained Earnings	229,812	187,875
Accumulated Other Comprehensive Income (Loss)	(33,871)	(25,106)
Total Common Shareholder's Equity	1,111,326	1,078,047
Cumulative Preferred Stock - Not Subject to Mandatory Redemption	8,084	8,101
Total Shareholders' Equity	1,119,410	1,086,148
Liability for Cumulative Preferred Stock - Subject to Mandatory Redemption	61,445	63,445
Long-term Debt	1,137,189	1,134,359
TOTAL	2,318,044	2,283,952
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	-	205,000
Advances from Affiliates	98,762	98,822
Accounts Payable:		
General	88,262	101,776
Affiliated Companies	37,114	47,484
Customer Deposits	31,070	21,955
Taxes Accrued	97,266	42,189
Interest Accrued	20,705	17,963
Risk Management Liabilities	71,476	31,898
Obligations Under Capital Leases	5,984	6,528
Other	80,790	57,675
TOTAL	531,429	631,290
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	321,376	337,376
Regulatory Liabilities:		
Asset Removal Costs	274,281	263,015
Deferred Investment Tax Credits	84,782	90,278
Excess ARO for Nuclear Decommissioning	232,569	215,715
Other	65,012	61,268
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	67,398	70,179
Long-term Risk Management Liabilities	39,823	33,537
Obligations Under Capital Leases	35,966	31,315
Asset Retirement Obligations	582,827	553,219
Deferred Credits and Other	88,586	87,927
TOTAL	1,792,620	1,743,829
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$4,642,093	$4,659,071

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$121,586	$63,452
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	-	3,160
Depreciation and Amortization	128,581	130,020
Deferred Income Taxes	2,772	(17,767)
Deferred Investment Tax Credits	(5,496)	(5,504)
Deferred Property Taxes	10,020	9,930
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	31,195	(4,049)
Unrecovered Fuel and Purchased Power Costs	452	28,126
Amortization of Nuclear Outage Costs	-	30,000
Mark-to-Market of Risk Management Contracts	10,760	30,661
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	41,624	68,914
Fuel, Materials and Supplies	(20,210)	(2,488)
Accounts Payable, Net	(23,884)	(95,624)
Customer Deposits	9,115	3,874
Taxes Accrued	55,077	(28,144)
Rent Accrued - Rockport Plant Unit 2	18,464	18,464
Change in Other Assets	(2,377)	(34,012)
Change in Other Liabilities	29,490	(7,995)
Net Cash Flows From Operating Activities	407,169	191,018
INVESTING ACTIVITIES		
Construction Expenditures	(122,756)	(108,201)
Other	874	1,655
Change in Other Cash Deposits, Net	(31)	(28)
Net Cash Flows Used For Investing Activities	(121,913)	(106,574)
FINANCING ACTIVITIES		
Retirement of Cumulative Preferred Stock	(2,011)	(1,500)
Retirement of Long-term Debt - Nonaffiliated	(205,155)	(255,000)
Change in Advances to/from Affiliates, Net	(60)	205,155
Dividends Paid on Common Stock	(79,293)	(30,000)
Dividends Paid on Cumulative Preferred Stock	(255)	(2,289)
Net Cash Flows Used For Financing Activities	(286,774)	(83,634)
Net Increase (Decrease) in Cash and Cash Equivalents	(1,518)	810
Cash and Cash Equivalents at Beginning of Period	3,899	3,251
Cash and Cash Equivalents at End of Period	$2,381	$4,061

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $46,694,000 and $59,359,000 and for income taxes was $(4,725,000) and $79,880,000 in 2004 and 2003, respectively. Noncash acquisitions under capital leases were $5,303,000 in 2004. There were no noncash capital lease acquisitions in 2003.

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to I&M's consolidated financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to I&M.

	Footnote
Reference	

Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Customer Choice and Industry Restructuring	Note 4
Commitments and Contingencies	Note 5
Guarantees	Note 6
Benefit Plans	Note 8
Business Segments	Note 9
Financing Activities	Note 10

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Net Income for the third quarter of 2004 decreased $341 thousand from the prior year period as increased retail revenues were offset by increased Fuel for Electric Generation expenses and decreased Nonoperating Income (Loss) due to unfavorable risk management activities.

Net Income for the nine months ended September 30, 2004 increased $1 million from the prior year period primarily due to the Cumulative Effect of Accounting Change recorded in 2003.

Third Quarter 2004 Compared to Third Quarter 2003

Operating Income

Operating Income for the third quarter of 2004 increased slightly from the prior year period primarily due to the following:

o A $7 million increase in Electric Generation, Transmission and Distribution revenues primarily relating to increased retail revenues. The retail revenues increased primarily due to an increase in industrial sales related to improvements in the economy as well as the recovery of increased fuel costs.
o A $3 million increase in Sales to AEP Affiliates relating to a 5% increase in Rockport plant generation enabling us to sell additional power to affiliates in comparison to the prior year period.
o A $2 million decrease in Income Taxes. See Income Taxes section below for further discussion.

The increase in Operating Income for the third quarter of 2004 compared to the prior year period was partially offset by the following:

o A $10 million increase in Fuel for Electric Generation expenses primarily resulting from an increase in the cost of coal consumed and an unfavorable impact of recording a liability for over-collection of fuel costs. This over-collection will be refunded to customers over the twelve months beginning November 2004.
o A $2 million increase in Purchased Electricity from AEP Affiliates resulting from purchases in accordance with the unit power agreement with AEGCo reflecting the 5% increase in generation at the Rockport plant. Our energy purchases from the Rockport plant are 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 (Loss) decreased $1 million in the third quarter of 2004 compared to the prior year period primarily due to unfavorable results from risk management activities.

Income Taxes

The effective tax rates for the third quarter of 2004 and 2003 were 11.4% and 36.4%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to federal income tax return adjustments and changes in flow-through temporary differences.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Operating Income

Operating Income for the nine months ended September 30, 2004 increased slightly from the prior year period primarily due to:

o A $20 million increase in Electric Generation, Transmission and Distribution revenues primarily related to increased retail revenues. The retail revenues increased primarily due to an environmental surcharge increase in July 2003, a 24% increase in cooling degree days, and an increase in industrial sales due to the recovering economy.
o A $6 million decrease in Purchased Electricity from AEP Affiliates resulting from a 19% increase in Big Sandy's generation in 2004 related to planned outages in 2003 for the installation of emission control equipment. The 2004 increase in generation from the Big Sandy plant reduced our need to purchase additional power from AEP affiliates.
o A $5 million decrease in Income Taxes. See Income Taxes section below for further discussion.
o A $3 million increase in Sales to AEP Affiliates reflecting recovery of increased fuel expenses.

The increase in Operating Income for the nine months ended September 30, 2004 was partially offset by:

o A $23 million increase in Fuel for Electric Generation expenses resulting from a 19% increase in generation for 2004 over 2003 and an increase in the average cost per ton of fuel consumed in the same period. In addition, Fuel for Electric Generation expense was unfavorably affected due to the impact of recording a liability for over-collection of fuel costs. This over- collection will be refunded over the twelve months beginning November 2004.
o A $4 million increase in Depreciation and Amortization expense in 2004 primarily resulting from the installation of emission control equipment at the Big Sandy plant in mid-2003.
o A $3 million increase in Maintenance expenses relating to planned outages for boiler overhauls in 2004.
o A $3 million increase in Other Operation expenses for 2004 relating to increased administrative and support expenses.

Other Impacts on Earnings

Nonoperating Income (Loss) increased $3 million in the nine months ended September 30, 2004 compared to the prior year period primarily due to favorable results from risk management activities.

Interest Charges increased $1 million in the nine months ended September 30, 2004 compared to the prior year period primarily due to reduced capitalized interest as well as increased long-term debt outstanding.

Income Taxes

The effective tax rates for the first nine months of 2004 and 2003 were 27.4% and 35.5%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to federal income tax return adjustments, changes in flow-through temporary differences, and lower state income taxes.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2004 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Notes Payable - Affiliated	$20,000	5.25	2015

Retirements

None

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report 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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$15,490
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(5,552)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(81)
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	686
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(344)
Total MTM Risk Management Contract Net Assets	10,199
Net Cash Flow Hedge Contracts (f)	(409)
DETM Assignment (g)	(6,051)
Total MTM Risk Management Contract Net Assets at September 30, 2004	$3,739

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(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) "Changes 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.
(f) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g) See Note 17 "Related Party Transactions" in the 2003 Annual Report.

Reconciliation of MTM Risk Management Contracts to

Balance Sheets
As of September 30, 2004

	MTM Risk Management Contracts(a)	Cash Flow Hedges	DETM Assignment(b)	Total(c)
	(in thousands)			
Current Assets	$20,549	$996	$-	$21,545
Non Current Assets	19,057	133	-	19,190
Total MTM Derivative Contract Assets	39,606	1,129	-	40,735
Current Liabilities	(18,843)	(1,207)	(2,493)	(22,543)
Non Current Liabilities	(10,564)	(331)	(3,558)	(14,453)
Total MTM Derivative Contract Liabilities	(29,407)	(1,538)	(6,051)	(36,996)
Total MTM Derivative Contract Net Assets (Liabilities)	$10,199	$(409)	$(6,051)	$3,739

(a) Does not include Cash Flow Hedges.
(b) See Note 17 "Related Party Transactions" in the 2003 Annual Report.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Balance Sheets.

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

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

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, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$512	$(1,531)	$7	$485	$-	$-	$(527)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(709)	2,982	774	492	-	-	3,539
Prices Based on Models and Other Valuation Methods (b)	180	750	993	827	1,369	3,068	7,187
Total	$(17)	$2,201	$1,774	$1,804	$1,369	$3,068	$10,199

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) There is mark-to-market value in excess of 10 percent of our total mark- to-market value in individual periods beyond 2008. $1.4 million of this mark-to-market value is in 2009 and $1.4 million of this mark-to-market is in 2010.
(d) Amounts exclude Cash Flow Hedges.

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

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

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

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2004

	Power	Interest Rate	Total
		(in thousands)	
Beginning Balance December 31, 2003	$82	$338	$420
Changes in Fair Value (a)	(618)	-	(618)
Reclassifications from AOCI to Net Income (b)	(322)	(65)	(387)
Ending Balance September 30, 2004	$(858)	$273	$(585)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $590 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Nine Months Ended September 30, 2004				Twelve Months Ended December 31, 2003			
(in thousands)				(in thousands)			
End	High	Average	Low	End	High	Average	Low
$71	$397	$184	$64	$136	$527	$220	$52

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $25 million and $29 million at September 30, 2004 and December 31, 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or financial position.

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$100,393	$93,500	$301,328	$281,755
Sales to AEP Affiliates	13,111	10,193	32,096	29,496
TOTAL	113,504	103,693	333,424	311,251
OPERATING EXPENSES				
Fuel for Electric Generation	29,380	19,608	75,498	52,994
Purchased Electricity from AEP Affiliates	37,725	35,461	102,848	109,008
Other Operation	12,848	12,519	39,128	36,351
Maintenance	5,925	6,671	23,464	20,597
Depreciation and Amortization	11,004	10,693	32,768	28,653
Taxes Other Than Income Taxes	2,208	2,300	6,931	6,742
Income Taxes	935	3,344	8,489	13,011
TOTAL	100,025	90,596	289,126	267,356
OPERATING INCOME	13,479	13,097	44,298	43,895
Nonoperating Income (Loss)	(137)	1,309	1,297	(1,636)
Nonoperating Expenses	168	192	1,755	554
Nonoperating Income Tax Expense (Credit)	(144)	370	(238)	(1,114)
Interest Charges	7,158	7,343	22,239	21,202
Income Before Cumulative Effect of Accounting Change	6,160	6,501	21,839	21,617
Cumulative Effect of Accounting Change (Net of Tax)	-	-	-	(1,134)
NET INCOME	$6,160	$6,501	$21,839	$20,483

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

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$50,450	$208,750	$48,269	$(9,451)	$298,018
Common Stock Dividends			(16,448)		(16,448)
TOTAL					281,570
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				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
DECEMBER 31, 2003	$50,450	$208,750	$64,151	$(6,213)	$317,138
Common Stock Dividends			(16,000)		(16,000)
TOTAL					301,138
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(1,005)	(1,005)
NET INCOME			21,839		21,839
TOTAL COMPREHENSIVE INCOME					20,834
SEPTEMBER 30, 2004	$50,450	$208,750	$69,990	$(7,218)	$321,972

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$461,980	$457,341
Transmission	384,401	381,354
Distribution	436,768	425,688
General	59,662	68,041
Construction Work in Progress	13,539	17,322
TOTAL	1,356,350	1,349,746
Accumulated Depreciation and Amortization	395,216	381,876
TOTAL - NET	961,134	967,870
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	5,440	5,423
Other Investments	398	1,022
TOTAL	5,838	6,445
CURRENT ASSETS		
Cash and Cash Equivalents	642	863
Other Cash Deposits	12	23
Advances to Affiliates	37,779	-
Accounts Receivable:		
Customers	18,426	21,177
Affiliated Companies	19,630	25,327
Accrued Unbilled Revenues	3,461	5,534
Miscellaneous	90	97
Allowance for Uncollectible Accounts	(25)	(736)
Fuel	6,873	9,481
Materials and Supplies	19,309	16,585
Risk Management Assets	21,545	16,200
Margin Deposits	1,277	2,660
Prepayments and Other	2,261	1,696
TOTAL	131,280	98,907
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	103,749	99,828
Other Regulatory Assets	15,779	13,971
Long-term Risk Management Assets	19,190	16,134
Deferred Property Taxes	1,756	6,847
Other Deferred Charges	11,884	11,632
TOTAL	152,358	148,412
TOTAL ASSETS	$1,250,610	$1,221,634

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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
Retained Earnings	69,990	64,151
Accumulated Other Comprehensive Income (Loss)	(7,218)	(6,213)
Total Common Shareholder's Equity	321,972	317,138
Long-term Debt:		
Nonaffiliated	428,592	427,602
Affiliated	80,000	60,000
Total Long-term Debt	508,592	487,602
TOTAL	830,564	804,740
CURRENT LIABILITIES		
Advances from Affiliates	-	38,096
Accounts Payable:		
General	28,198	22,802
Affiliated Companies	23,913	22,648
Customer Deposits	12,722	9,894
Taxes Accrued	11,341	7,329
Interest Accrued	9,074	6,915
Risk Management Liabilities	22,543	11,704
Obligations Under Capital Leases	1,618	1,743
Other	8,224	8,628
TOTAL	117,633	129,759
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	222,036	212,121
Regulatory Liabilities:		
Asset Removal Costs	27,403	26,140
Deferred Investment Tax Credits	7,078	7,955
Other Regulatory Liabilities	14,765	10,591
Long-term Risk Management Liabilities	14,453	12,363
Obligations Under Capital Leases	2,987	3,549
Deferred Credits and Other	13,691	14,416
TOTAL	302,413	287,135
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,250,610	$1,221,634

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$21,839	$20,483
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	-	1,134
Depreciation and Amortization	32,768	28,653
Deferred Income Taxes	6,536	16,020
Deferred Investment Tax Credits	(877)	(880)
Deferred Property Taxes	5,091	4,698
Deferred Fuel Costs, Net	1,886	(772)
Loss on Sale of Assets	1,062	-
Mark-to-Market of Risk Management Contracts	3,994	9,950
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	9,817	13,326
Fuel, Materials and Supplies	(116)	(613)
Accounts Payable, Net	6,661	(39,620)
Taxes Accrued	4,012	1,455
Change in Other Assets	(6,344)	(6,753)
Change in Other Liabilities	10,621	(61)
Net Cash Flows From Operating Activities	96,950	47,020
INVESTING ACTIVITIES		
Construction Expenditures	(26,845)	(71,154)
Proceeds from Sales of Property and Other	1,538	967
Change in Other Cash Deposits, Net	11	(4)
Net Cash Flow Used for Investing Activities	(25,296)	(70,191)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Affiliated	20,000	74,263
Retirement of Long-term Debt - Nonaffiliated	-	(40,000)
Retirement of Long-term Debt - Affiliated	-	(15,000)
Change in Advances to/from Affiliates, Net	(75,875)	18,809
Dividends Paid	(16,000)	(16,448)
Net Cash Flows From (Used For) Financing Activities	(71,875)	21,624
Net Decrease in Cash and Cash Equivalents	(221)	(1,547)
Cash and Cash Equivalents at Beginning of Period	863	2,285
Cash and Cash Equivalents at End of Period	$642	$738

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $19,198,000 and $17,925,000 and for income taxes was $(3,233,000) and $(7,605,000) in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to KPCo's financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to KPCo.

Results of Operations

Net Income decreased $20 million for the quarter primarily due to an $11 million decrease in retail revenues driven by lower residential and commercial sales and a $9 million favorable adjustment recorded in September 2003 for decreased costs associated with coal companies sold prior to 2003.

Net Income decreased $150 million year-to-date primarily due to a $125 million Cumulative Effect of Accounting Changes in the first quarter of 2003. Income Before Cumulative Effect decreased $25 million year-to-date primarily due to a decrease in sales for resale.

Effective July 1, 2003, we consolidated JMG Funding, LP (JMG) as a result of the implementation of FIN 46. We record depreciation, interest and other operating expenses of JMG and eliminate JMG's revenues against our operating lease expenses. While there was no effect to net income as a result of consolidation, some individual income statement captions are affected.

Third Quarter 2004 Compared to Third Quarter 2003

Operating Income

Operating Income for the third quarter of 2004 decreased $13 million from the prior year period due to:

o An $11 million decrease in retail sales resulting from decreased weather- related demand from residential and commercial customers.
o A $9 million increase in Fuel for Electric Generation primarily due to a 12% increase in the cost of coal consumed and a $4 million favorable coal survey adjustment recorded in September 2003.
o A $2 million increase in Purchased Electricity from AEP Affiliates due to a 9% increase in MWHs purchased as a result of forced generating unit outages.
o A $2 million increase in Maintenance due to increases in scheduled and forced boiler, electric and steam plant maintenance partially offset by a reduction in costs associated with maintaining overhead lines.
o A $4 million increase in Depreciation and Amortization primarily associated with a greater depreciable base in 2004, including capitalized software costs and the increased amortization of transition generation regulatory assets due to normal operating adjustments.

The decrease in Operating Income for the third quarter of 2004 was partially offset by:

o A $6 million increase in operating revenues related to risk management activities.
o A $4 million decrease in Other Operation expense primarily due to gains on disposition of allowances.
o A $7 million decrease in Income Taxes. See Income Taxes section below for further discussion.

Other Impacts of Earnings

Nonoperating Income for the third quarter of 2004 increased $27 million from the prior year period primarily due to:

o $36 million in sales of excess energy purchased from Dow at the Plaquemine, Louisiana plant (see Note 5) including the effects of a related affiliate agreement which eliminates our market exposure related to the purchases from Dow. There was no change in overall net income due to the agreement with Dow. These sales in 2004 were offset by a $9 million favorable adjustment recorded in September 2003 for decreased costs associated with coal companies sold prior to 2003.

Nonoperating Expenses for the third quarter of 2004 increased $43 million from the prior year period primarily due to:

o $38 million from the agreement to purchase excess energy from Dow at the Plaquemine, Louisiana plant (see Note 5). There was no change in overall net income due to the agreement with Dow.
o $4 million of unfavorable risk management activities.

Nonoperating Income Tax Expense decreased $4 million. See Income Taxes section below for further discussion.

Interest charges for the third quarter of 2004 decreased $5 million from the prior year period primarily due to redemption of higher cost First Mortgage Bonds and Senior Unsecured Notes replaced with Affiliated Notes Payable at lower interest rates.

Income Taxes

The effective tax rates for the third quarter of 2004 and 2003 were 32.3% and 33.3%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Operating Income

Operating Income for the nine months ended September 30, 2004 decreased $20 million compared to the prior year period due to:

o A $9 million decrease in non-affiliated wholesale energy sales due to a lower sales volume.
o A $12 million decrease in non-affiliated system sales due to a 12% decrease in MWHs sold.
o A $9 million decrease in Sales to AEP Affiliates. The decrease is primarily the result of an 8.6% decrease in MWH for affiliated system sales partially offset by a $5 million increase in capacity credit.
o A $7 million decrease in other operating revenue primarily due to the expiration of a contract with Buckeye Power.
o A $14 million increase in Fuel for Electric Generation due to higher coal cost.
o A $4 million increase in Maintenance due primarily to boiler overhaul work from scheduled and forced outages and turbine repairs.
o A $25 million increase in Depreciation and Amortization primarily associated with the consolidation of JMG. Depreciation expense related to the assets owned by JMG were consolidated effective July 1, 2003 (there was no change in overall net income due to the consolidation of JMG). In addition, the increase is a result of a greater depreciable base in 2004, including capitalized software and the increased amortization of transition generation regulatory assets due to normal operating adjustments.

The decrease in Operating Income for the nine months ended September 30, 2004 was partially offset by:

o A $6 million increase in retail electric revenues resulting from increased demand from industrial customers.
o A $15 million increase in operating revenues related to favorable risk management activities.
o An $11 million decrease in Purchased Electricity for Resale primarily due to cessation of the Buckeye Transmission agreement on June 30, 2003. Prior to this date, Ohio Edison interchange expenses were recorded in Purchased Electricity for Resale. An associated offsetting decrease in Ohio Edison revenue occurred in non affiliated sales for resale; therefore, there was no effect to net income. In addition, the DOE Settlement Capacity Surcharge was included in rates through April 30, 2003, which is no longer in effect for 2004.
o A $29 million decrease in Income Taxes. See Income Taxes section below for further discussion.

Other Impacts of Earnings

Nonoperating Income increased $95 million primarily due to sales of excess energy purchased from Dow at the Plaquemine, Louisiana plant (see Note 5) including the effects of a related affiliate agreement which eliminates our market exposure related to the purchases from Dow. There was no change in overall net income due to the agreement with Dow. In addition, income from nonoperating risk management contributed to this increase.

Nonoperating Expense increased $82 million primarily due to the agreement to purchase excess energy from Dow at the Plaquemine, Louisiana plant (see Note 5). There was no change in overall net income due to the agreement with Dow.

Interest charges increased $17 million primarily due to the consolidation of JMG and its associated debt along with issuance of additional long-term debt in July 2003. There was no change in overall net income due to the consolidation of JMG.

Income Taxes

The effective tax rates for the first nine months of 2004 and 2003 were 34.3% and 37.5%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower state income taxes and federal income tax return adjustments.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes during 2003 of $125 million was due to the one-time after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
Senior Unsecured Debt	A3	BBB	BBB+

Cash Flow

Cash flows for the nine months ended September 30, 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$7,233	$5,275
Cash flows from (used for):		
Operating activities	447,996	225,658
Investing activities	(151,809)	(160,295)
Financing activities	(299,977)	(63,986)
Net increase (decrease) in cash and cash equivalents	(3,790)	1,377
Cash and cash equivalents at end of period	$3,443	$6,652

Operating Activities

Cash Flows From Operating Activities for the nine months ended September 30, 2004 increased $222 million compared to the prior year period. This is primarily due to significant reductions in Accounts Payable balances during the second quarter of 2003 partially associated with a wind-down of risk management activities in that year.

Investing Activities

Cash Flows Used For Investing Activities were $152 million during the nine months ended September 30, 2004 primarily due to new expenditures for Generation, Transmission, Distribution and Environmental offset by a Change in Other Cash Deposits, Net primarily as a result of monies set aside in 2003 for the retirement of Installment Purchase Contracts in 2004. For the remainder of 2004, we expect our Construction Expenditures to be approximately $107 million.

Financing Activities

Cash Flows For Financing Activities used $300 million in the nine months ended September 30, 2004 and $64 million in the prior year period. This is primarily due to a decrease in the change in Advances to/from Affiliates, Net, during 2004 as a result of becoming a net lender as opposed to a net borrower.

Financing Activity

Long-term debt issuances and retirements during the nine months ended September 30, 2004 were:

Issuances

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Notes Payable - Affiliates	$200,000	5.25	2015
Notes Payable - Affiliates	200,000	3.32	2006

Retirements

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Installment Purchase Contracts	$50,000	6.85	2022
Notes Payable	3,000	6.27	2009
Notes Payable	4,390	6.81	2008
First Mortgage Bonds	10,000	7.30	2024
Senior Unsecured Notes	140,000	7.375	2038
Senior Unsecured Notes	100,000	6.75	2004
Senior Unsecured Notes	75,000	7.00	2004

Other

Power Generation Facility

AEP has agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to AEP. AEP has subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004.

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

OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market.

Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as non-conforming. Commercial operation for purposes of the PPA began April 2, 2004.

On September 5, 2003, TEM and OPCo separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. OPCo alleges that TEM has breached the PPA, and is seeking a determination of OPCo's rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of OPCo's breaches. If the PPA is deemed terminated or found to be unenforceable by the court, OPCo could be adversely affected to the extent it is unable to find other purchasers of the power with similar contractual terms and to the extent OPCo does not fully recover claimed termination value damages from TEM. However, OPCo has entered into an agreement with an affiliate that eliminates OPCo's market exposure related to the PPA. The corporate parent of TEM (Tractebel SA) has provided a limited guaranty.

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

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

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report 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

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

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$53,938
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(25,715)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(277)
Change in Fair Value Due to Valuation Methodology Changes (d)	1,189
Changes in Fair Value of Risk Management Contracts (e)	9,825
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	38,960
Net Cash Flow Hedge Contracts (g)	(4,744)
DETM Assignment (h)	(20,709)
Total MTM Risk Management Contracts Net Assets at September 30, 2004	$13,507

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

(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 2004. 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 2004.

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

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

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

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

(h) See Note 17 "Related Party Transactions" in the 2003 Annual Report.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheets
As of September 30, 2004

(c)	MTM Risk Management Contracts(a)	Cash Flow Hedges	DETM Assignment(b)	Consolidated
	(in thousands)			
Current Assets	$80,477	$1,282	$-	$81,759
Non Current Assets	68,558	452	-	69,010
Total MTM Derivative Contract Assets	149,035	1,734	-	150,769
Current Liabilities	(71,669)	(5,329)	(8,534)	(85,532)
Non Current Liabilities	(38,406)	(1,149)	(12,175)	(51,730)
Total MTM Derivative Contract Liabilities	(110,075)	(6,478)	(20,709)	(137,262)
Total MTM Derivative Contract Net Assets (Liabilities)	$38,960	$(4,744)	$(20,709)	$13,507

(a) Does not include Cash Flow Hedges.

(b) See Note 17 "Related Party Transactions" in the 2003 Annual Report.

(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$1,751	$(5,240)	$22	$1,660	$-	$-	$(1,807)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(2,174)	13,544	2,869	2,243	-	-	16,482
Prices Based on Models and Other Valuation Methods (b)	630	2,168	3,506	2,794	4,685	10,502	24,285
Total	$207	$10,472	$6,397	$6,697	$4,685	$10,502	$38,960

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008. $4.8 million of this mark-to-market value is in 2009 and $4.6 million of this mark-to-market is in 2010.
(d) Amounts exclude Cash Flow Hedges.

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

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

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

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2004

	Power	Foreign Currency
Consolidated		

		(in thousands)	
Beginning Balance December 31, 2003	$268	$(371)	$(103)
Changes in Fair Value (a)	(2,270)	-	(2,270)
Reclassifications from AOCI to Net Income (b)	(1,120)	10	(1,110)
Ending Balance September 30, 2004	$(3,122)	$(361)	$(3,483)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.

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

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2,683 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Nine Months Ended September 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$244	$1,357	$631	$220	$444	$1,724	$722	$172

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $167 million and $214 million at September 30, 2004 and December 31, 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$410,514	$418,083	$1,251,377	$1,256,862
Sales to AEP Affiliates	147,602	147,235	429,503	438,473
TOTAL	558,116	565,318	1,680,880	1,695,335
OPERATING EXPENSES				
Fuel for Electric Generation	164,353	155,222	476,127	462,316
Purchased Electricity for Resale	14,456	15,219	40,794	52,064
Purchased Electricity from AEP Affiliates	26,007	23,693	68,479	70,905
Other Operation	87,981	92,376	272,900	269,998
Maintenance	41,047	38,598	131,831	127,466
Depreciation and Amortization	71,857	67,365	214,027	189,140
Taxes Other Than Income Taxes	44,681	45,582	135,517	132,350
Income Taxes	26,897	33,465	89,099	118,597
TOTAL	477,279	471,520	1,428,774	1,422,836
OPERATING INCOME	80,837	93,798	252,106	272,499
Nonoperating Income	46,362	19,255	116,174	21,354
Nonoperating Expenses	50,809	7,528	108,109	26,569
Nonoperating Income Tax Expense (Credit)	(2,660)	1,646	(693)	(1,446)
Interest Charges	28,365	33,512	91,232	73,736
Income Before Cumulative Effect of Accounting Changes	50,685	70,367	169,632	194,994
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	-	124,632
NET INCOME	50,685	70,367	169,632	319,626
Preferred Stock Dividend Requirements	184	286	550	915
EARNINGS APPLICABLE TO COMMON STOCK	$50,501	$70,081	$169,082	$318,711

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

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$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 Gains		1			1
TOTAL					1,106,400
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
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
DECEMBER 31, 2003	$321,201	$462,484	$729,147	$(48,807)	$1,464,025
Common Stock Dividends			(144,114)		(144,114)
Preferred Stock Dividends			(550)		(550)
TOTAL					1,319,361
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(3,380)	(3,380)
Minimum Pension Liability				(3,942)	(3,942)
NET INCOME			169,632		169,632
TOTAL COMPREHENSIVE INCOME					162,310
SEPTEMBER 30, 2004	$321,201	$462,484	$754,115	$(56,129)	$1,481,671

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$4,102,622	$4,029,515
Transmission	969,848	938,805
Distribution	1,191,189	1,156,886
General	251,720	245,434
Construction Work in Progress	162,450	142,951
Total	6,677,829	6,513,591
Accumulated Depreciation and Amortization	2,582,823	2,485,947
TOTAL - NET	4,095,006	4,027,644
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	45,788	47,015
Other	58,550	24,264
TOTAL	104,338	71,279
CURRENT ASSETS		
Cash and Cash Equivalents	3,443	7,233
Other Cash Deposits	50	51,017
Advances to Affiliates	232,212	67,918
Accounts Receivable:		
Customers	99,840	100,960
Affiliated Companies	112,234	120,532
Accrued Unbilled Revenues	8,597	17,221
Miscellaneous	679	736
Allowance for Uncollectible Accounts	(581)	(789)
Fuel	81,785	77,725
Materials and Supplies	97,480	92,136
Risk Management Assets	81,759	56,265
Margin Deposits	4,962	9,296
Prepayments and Other	15,520	15,883
TOTAL	737,980	616,133
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	171,328	169,605
Transition Regulatory Assets	246,472	310,035
Unamortized Loss on Reacquired Debt	11,225	10,172
Other	24,101	22,506
Long-term Risk Management Assets	69,010	52,825
Deferred Property Taxes	20,665	67,469
Deferred Charges and Other Assets	38,951	26,850
TOTAL	581,752	659,462
TOTAL ASSETS	$5,519,076	$5,374,518

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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	462,484
Retained Earnings	754,115	729,147
Accumulated Other Comprehensive Income (Loss)	(56,129)	(48,807)
Total Common Shareholder's Equity	1,481,671	1,464,025
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,644	16,645
Total Shareholders' Equity	1,498,315	1,480,670
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	5,000	7,250
Long-term Debt:		
Nonaffiliated	1,600,056	1,608,086
Affiliated	400,000	-
Total Long-term Debt	2,000,056	1,608,086
TOTAL	3,503,371	3,096,006
Minority Interest	14,676	16,314
CURRENT LIABILITIES		
Short-term Debt - General	19,562	25,941
Long-term Debt Due Within One Year - Nonaffiliated	60,354	431,854
Accounts Payable:		
General	119,404	104,874
Affiliated Companies	90,555	101,758
Customer Deposits	27,908	17,308
Taxes Accrued	184,503	132,793
Interest Accrued	26,339	45,679
Risk Management Liabilities	85,532	38,318
Obligations Under Capital Leases	8,760	9,624
Other	71,807	71,642
TOTAL	694,724	979,791
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	933,443	933,582
Regulatory Liabilities:		
Asset Removal Costs	104,974	101,160
Deferred Investment Tax Credits	13,357	15,641
Other	-	3
Long-term Risk Management Liabilities	51,730	40,477
Deferred Credits	26,225	23,222
Obligations Under Capital Leases	32,899	25,064
Asset Retirement Obligations	45,204	42,656
Other	98,473	100,602
TOTAL	1,306,305	1,282,407
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,519,076	$5,374,518

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$169,632	$319,626
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(124,632)
Depreciation and Amortization	214,027	189,140
Deferred Income Taxes	2,080	4,139
Deferred Investment Tax Credits	(2,283)	(2,288)
Deferred Property Taxes	46,804	46,491
Mark-to-Market of Risk Management Contracts	11,632	40,283
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	17,891	37,799
Fuel, Materials and Supplies	(9,404)	4,515
Prepayments and Other Current Assets	4,697	(9,030)
Accounts Payable, Net	3,327	(215,012)
Customer Deposits	10,600	3,579
Taxes Accrued	51,710	(17,682)
Interest Accrued	(19,340)	9,516
Change in Other Assets	(51,835)	(2,859)
Change in Other Liabilities	(1,542)	(57,927)
Net Cash Flows From Operating Activities	447,996	225,658
INVESTING ACTIVITIES		
Construction Expenditures	(205,752)	(163,864)
Change in Other Cash Deposits, Net	50,967	(51)
Proceeds from Sale of Property and Other	2,976	3,620
Net Cash Flows Used For Investing Activities	(151,809)	(160,295)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	-	938,914
Issuance of Long-term Debt - Affiliated	400,000	-
Change in Advances to/from Affiliates, Net	(164,294)	(272,872)
Change in Short-term Debt, Net	(6,379)	2,039
Change in Short-term Debt - Affiliates, Net	-	(275,000)
Retirement of Long-term Debt - Nonaffiliated	(382,390)	(29,850)
Retirement of Long-term Debt - Affiliated	-	(300,000)
Retirement of Cumulative Preferred Stock	(2,250)	(502)
Dividends Paid on Common Stock	(144,114)	(125,800)
Dividends Paid on Cumulative Preferred Stock	(550)	(915)
Net Cash Flows Used For Financing Activities	(299,977)	(63,986)
Net Increase (Decrease) in Cash and Cash Equivalents	(3,790)	1,377
Cash and Cash Equivalents at Beginning of Period	7,233	5,275
Cash and Cash Equivalents at End of Period	$3,443	$6,652

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $107,177,000 and $57,517,000 and for income taxes was $(21,600,000) and $74,858,000 in 2004 and 2003, respectively. Noncash acquisitions under capital leases were $12,749,000 in 2004. There were no noncash capital lease acquisitions in 2003.

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to OPCo's consolidated financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to OPCo.

Results of Operations

Net Income for the nine months ended September 30, 2004 decreased $19 million from the prior year period due to increased operations and maintenance expenses for power plant maintenance, transmission and tree trimming. Net Income increased $1 million for the third quarter.

Fluctuations occurring in the retail portion of fuel and purchased power expense generally do not impact operating income, as they are offset in revenues due to the functioning of the fuel clause adjustment in Oklahoma.

Third Quarter 2004 Compared to Third Quarter 2003

Operating Income

Operating Income for the third quarter of 2004 increased $4 million from the prior year period primarily due to:

o A $9 million increase in system sales margins.
o A $1 million decrease in Maintenance expenses primarily due to lower power plant expenses.

The increase in Operating Income for the third quarter of 2004 was partially offset by:

o A $4 million decrease in retail base revenue primarily due to a 19% decrease in cooling degree-days.
o A $3 million increase in Other Operation expenses primarily due to customer related expenses and administrative and general expenses.

Other Impacts on Earnings

Nonoperating Income decreased $6 million in the third quarter of 2004 compared to the prior year period primarily due to a gain on the disposition of land recorded in 2003.

Interest Charges decreased $2 million in the third quarter of 2004 compared to the prior year period due to reduced interest rates from refinancing higher cost debt.

Income Taxes

The effective tax rates for the third quarter of 2004 and 2003 were 37.6% and 40.5%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower state income taxes.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Operating Income

Operating Income for the nine months ended September 30, 2004 in comparison to the prior year period decreased $20 million primarily due to:

o A $20 million increase in Other Operation expenses. Transmission expense increased $9 million primarily related to prior years true-up for OATT transmission recorded in 2004 resulting from revised data from ERCOT for the years 2001-2003. Distribution expenses increased $5 million resulting mainly from a labor settlement and various inventory and tracking system upgrades.
o A $13 million increase in Maintenance expenses primarily due to increased power plant maintenance and tree trimming along with increased repairs of storm damage.
o A $3 million decrease in transmission revenues primarily due to non- affiliated transactions.
o A $1 million increase in Taxes Other Than Income Taxes primarily due to increased property taxes attributable to changes in property values and employee-related taxes offset in part by lower franchise taxes.

The decrease in Operating Income for the nine months ended September 30, 2004 was partially offset by:

o A $4 million increase in system sales margins due to the end of merger related mitigation sales losses in 2003.
o A $4 million increase in retail base revenue primarily due to increased KWH sales of 3%. Customer usage increased primarily from our industrial class and number of customers offset in part by a decrease in heating and cooling degree-days of 13%.

Other Impacts on Earnings

Nonoperating Income decreased $6 million in the nine months ended September 30, 2004 compared to the prior year period primarily due to a gain on the disposition of land recorded in 2003.

Interest Charges decreased $7 million in the nine months ended September 30, 2004 compared to the prior year period due to reduced interest rates from refinancing higher cost debt.

Income Taxes

The effective tax rates for the first nine months of 2004 and 2003 were 32.2% and 34.1%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes.

Financial Condition

Credit Ratings

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

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

In July 2004, Standard and Poor's upgraded the credit rating of the First Mortgage Bonds from BBB to A- due to a change in rating methodology. The principal amount of First Mortgage Bonds currently outstanding is $100 million.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2004 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contracts	$33,700	Variable	2014
Senior Unsecured Notes	50,000	4.70	2009

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date

	(in thousands)	(%)	
Notes Payable to Trust	$77,320	8.00	2037
Installment Purchase Contracts	33,700	4.875	2014
Installment Purchase Contracts	1,000	5.90	2007

Significant Factors

Oklahoma Regulatory Activity

We filed with the Corporation Commission of the State of Oklahoma (OCC) for recovery of a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West electric operating companies of purchased power costs for periods prior to January 1, 2002. The OCC has expanded the case to include a full review of our 2001 fuel and purchased power practices. Intervenor and OCC Staff filings in the case recommended a disallowance of $18 million associated with the allocation of off-system sales margins. At a June 2004 prehearing conference, we questioned whether the issues in dispute were under the jurisdiction of the OCC because they relate to FERC-approved allocation agreements. As a result, the ALJ ordered that the parties brief the jurisdictional issue. We filed our brief on September 1, 2004. Subject to the OCC's decision as to jurisdiction, a hearing date has been set for January 2005. Management believes that fuel costs have been prudently incurred consistent with OCC rules, and that the allocation of off-system sales margins was made pursuant to the FERC-approved allocation agreements. If the OCC determines that a portion of unrecovered fuel and purchased power costs should not be recovered, there will be, subject to the FERC jurisdictional question, an adverse effect on results of operations, cash flows and possibly financial condition.

In February 2003, the OCC filed an application requiring us to file all documents necessary for a general rate review. In October 2003 and June 2004, we filed financial information and supporting testimony in response to the OCC's requirements. The response indicates that annual revenues are $41 million less than costs. As a result, we are seeking OCC approval to increase base rates by that amount, which is a 3.9% increase over existing revenues. A decision is not expected until second quarter 2005. Management is unable to predict the ultimate effect of these proceedings on revenues, results of operations, cash flows and financial condition.

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section for additional discussion of other factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report 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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$14,057
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(980)
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	-
Changes in Fair Value of Risk Management Contracts (d)	-
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(2,905)
Total MTM Risk Management Contract Net Assets	10,023
Net Cash Flow Hedge Contracts (f)	(3,588)
Total MTM Risk Management Contract Net Assets at September 30, 2004	$6,435

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

(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 2004. 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 2004.

(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) "Changes 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.

(f) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to Balance Sheets
As of September 30, 2004

	MTM Risk Management Contracts(a)	Cash Flow Hedges	Total (b)
		(in thousands)	
Current Assets	$22,508	$293	$22,801
Non Current Assets	12,749	89	12,838
Total MTM Derivative Contract Assets	35,257	382	35,639
Current Liabilities	(19,258)	(3,361)	(22,619)
Non Current Liabilities	(5,976)	(609)	(6,585)
Total MTM Derivative Contract Liabilities	(25,234)	(3,970)	(29,204)

Total MTM Derivative Contract Net Assets (Liabilities)	$10,023	$(3,588)	$6,435
	========	========	========

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

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:
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, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
	(in thousands)						
Prices Actively Quoted - Exchange Traded Contracts	$940	$(2,814)	$12	$891	$-	$-	$(971)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(1,909)	6,566	586	-	-	-	5,243
Prices Based on Models and Other Valuation Methods (b)	2	1,357	283	(75)	1,023	3,161	5,751
Total	$(967)	$5,109	$881	$816	$1,023	$3,161	$10,023

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008. $1.2 million of this mark-to-market value is in 2009.
(d) Amounts exclude Cash Flow Hedges.

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

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

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

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Nine Months Ended September 30, 2004

Consolidated	Power	Interest Rate	Consolidated
	(in thousands)		
Beginning Balance December 31, 2003	$156	$-	$156
Changes in Fair Value (a)	(1,462)	-	(1,462)
Reclassifications from AOCI to Net Income (b)	(274)	(743)	(1,017)
Ending Balance September 30, 2004	$(1,580)	$(743)	$(2,323)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,298 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Nine Months Ended September 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$131	$729	$339	$118	$258	$1,004	$420	$100

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $35 million and $66 million at September 30, 2004 and December 31, 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$355,260	$355,064	$787,956	$860,544
Sales to AEP Affiliates	1,371	3,511	7,467	17,929
TOTAL	356,631	358,575	795,423	878,473
OPERATING EXPENSES				
Fuel for Electric Generation	139,712	177,162	315,803	415,731
Purchased Electricity for Resale	41,059	11,524	55,810	30,878
Purchased Electricity from AEP Affiliates	24,083	24,132	79,182	94,515
Other Operation	36,882	33,765	117,045	97,067
Maintenance	11,777	12,763	47,774	34,523
Depreciation and Amortization	22,762	21,715	67,097	64,568
Taxes Other Than Income Taxes	9,483	9,526	29,027	27,611
Income Taxes	23,671	24,461	18,767	28,192
TOTAL	309,429	315,048	730,505	793,085
OPERATING INCOME	47,202	43,527	64,918	85,388
Nonoperating Income	640	6,691	1,011	7,413
Nonoperating Expense	356	304	1,660	467
Nonoperating Income Tax Expense (Credit)	(162)	1,488	(1,021)	1,133
Interest Charges	8,668	10,336	27,922	34,493
NET INCOME	38,980	38,090	37,368	56,708
Preferred Stock Dividend Requirements	53	53	159	159
EARNINGS APPLICABLE TO COMMON STOCK	$38,927	$38,037	$37,209	$56,549

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

See Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$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:					
Cash Flow Hedges				(59)	(59)
Minimum Pension Liability				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
DECEMBER 31, 2003	$157,230	$230,016	$139,604	$(43,842)	$483,008
Common Stock Dividends			(26,250)		(26,250)
Preferred Stock Dividends			(159)		(159)
Gain on Reacquired Preferred Stock			2		2
TOTAL					456,601
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(2,479)	(2,479)
NET INCOME			37,368		37,368
TOTAL COMPREHENSIVE INCOME					34,889
SEPTEMBER 30, 2004	$157,230	$230,016	$150,565	$(46,321)	$491,490

See Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,070,014	$1,065,408
Transmission	455,065	458,577
Distribution	1,080,856	1,031,229
General	209,774	203,756
Construction Work in Progress	42,777	54,711
TOTAL	2,858,486	2,813,681
Accumulated Depreciation and Amortization	1,111,748	1,069,216
TOTAL - NET	1,746,738	1,744,465
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	4,402	4,631
Other Investments	-	2,320
TOTAL	4,402	6,951
CURRENT ASSETS		
Cash and Cash Equivalents	3,510	3,738
Other Cash Deposits	-	10,520
Accounts Receivable:		
Customers	26,953	28,515
Affiliated Companies	26,674	19,852
Miscellaneous	1,486	-
Allowance for Uncollectible Accounts	(29)	(37)
Fuel Inventory	17,788	18,331
Materials and Supplies	38,946	38,125
Regulatory Asset for Under-recovered Fuel Costs	26,044	24,170
Risk Management Assets	22,801	18,586
Margin Deposits	1,739	4,351
Prepayments and Other	2,073	2,655
TOTAL	167,985	168,806
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	15,268	14,357
Other	17,557	14,342
Long-term Risk Management Assets	12,838	10,379
Deferred Charges	27,245	18,017
TOTAL	72,908	57,095
TOTAL ASSETS	$1,992,033	$1,977,317

See Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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	230,016
Retained Earnings	150,565	139,604
Accumulated Other Comprehensive Income (Loss)	(46,321)	(43,842)
Total Common Shareholder's Equity	491,490	483,008
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,267
Total Shareholders' Equity	496,752	488,275
Long-term Debt	446,057	490,598
TOTAL	942,809	978,873
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	100,000	83,700
Advances from Affiliates	19,259	32,864
Accounts Payable:		
General	58,650	48,808
Affiliated Companies	41,390	57,206
Customer Deposits	34,476	26,547
Taxes Accrued	54,520	27,157
Interest Accrued	3,633	3,706
Risk Management Liabilities	22,619	11,067
Obligations Under Capital Leases	478	452
Other	22,250	35,234
TOTAL	357,275	326,741
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	346,444	335,434
Long-Term Risk Management Liabilities	6,585	3,602
Regulatory Liabilities:		
Asset Removal Costs	221,057	214,033
Deferred Investment Tax Credits	29,067	30,411
SFAS 109 Regulatory Liability, Net	23,112	24,937
Other	17,254	15,406
Obligations Under Capital Leases	597	558
Deferred Credits and Other	47,833	47,322
TOTAL	691,949	671,703
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,992,033	$1,977,317

See Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$37,368	$56,708
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	67,097	64,568
Deferred Income Taxes	10,519	6,536
Deferred Investment Tax Credits	(1,343)	(1,343)
Deferred Property Taxes	(8,648)	(8,239)
Mark-to-Market of Risk Management Contracts	4,034	(9,783)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(6,754)	(6,010)
Fuel, Materials and Supplies	(278)	1,353
Accounts Payable, Net	(5,974)	9,463
Taxes Accrued	27,363	12,342
Fuel Recovery	(1,874)	32,862
Changes in Other Assets	(12,326)	(7,492)
Changes in Other Liabilities	4,447	12,430
Net Cash Flows From Operating Activities	113,631	163,395
INVESTING ACTIVITIES		
Construction Expenditures	(55,929)	(59,263)
Proceeds from Sale of Property and Other	458	2,664
Change in Other Cash Deposits, Net	10,520	(2,916)
Net Cash Flows Used For Investing Activities	(44,951)	(59,515)
FINANCING ACTIVITIES		
Capital Contributions from Parent	-	50,000
Change in Advances to/from Affiliates, Net	(13,605)	(189,558)
Retirement of Long-term Debt	(112,020)	(100,000)
Issuance of Long-term Debt	83,129	148,734
Reacquired Preferred Stock	(3)	-
Dividends Paid on Common Stock	(26,250)	(15,000)
Dividends Paid on Cumulative Preferred Stock	(159)	(159)
Net Cash Flows Used For Financing Activities	(68,908)	(105,983)
Net Decrease in Cash and Cash Equivalents	(228)	(2,103)
Cash and Cash Equivalents at Beginning of Period	3,738	9,543
Cash and Cash Equivalents at End of Period	$3,510	$7,440

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $24,518,000 and $31,572,000 and for income taxes was $2,387,000 and $33,658,000 in 2004 and 2003, 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 Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to PSO's financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to PSO.

Reference	Footnote
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments and Contingencies	Note 5
Guarantees	Note 6
Benefit Plans	Note 8
Business Segments	Note 9
Financing Activities	Note 10

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

Results of Operations

Net Income decreased $2 million for 2004 year-to-date and increased $5 million for the third quarter. The year-to-date decrease is primarily due to the $9 million (net of tax) Cumulative Effect of Accounting Changes recorded in 2003. For the third quarter the increase is primarily due to favorable risk management activities.

Fluctuations occurring in the retail portion of fuel and purchased power expense generally do not impact operating income, as they are offset in revenues and/or operations expense due to the functioning of the fuel adjustment clauses in the states in which we serve.

Third Quarter 2004 Compared to Third Quarter 2003

Operating Income

Operating Income increased by $1 million primarily due to:

o A $4 million increase in margins from risk management activities.
o A $1 million increase in the portion of margin the company retains primarily due to increased realization of off-system sales.

The increase in Operating Income was partially offset by:

o A $3 million increase in Other Operation expenses primarily due to transmission expenses.
o A $3 million increase in Depreciation and Amortization expenses resulting from the amortization of a regulatory asset for the recovery of fuel related costs in Arkansas and adjustments to excess earnings accruals per the Texas Legislation (see "Texas Restructuring" in Note 4).
o A $2 million increase in provision for rate refund primarily due to a wholesale fuel refund.

Fuel and Purchased Power

For the third quarter of 2004 compared to third quarter 2003, purchased power expenses increased primarily due to an increase in KWH purchases of 35% and a cost per KWH increase of 32%. Fuel expenses decreased 30% due to lower KWH generation of 7% and lower cost per KWH of 14%. As discussed above, these items have no impact on Operating Income.

Other Impacts on Earnings

Interest Charges decreased $4 million as a result of refinancing higher interest rate debt and notes payable to trust with lower interest rate debt and notes payable to trust.

Income Taxes

The effective tax rates for the third quarter of 2004 and 2003 were 32.8% and 36.3%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to federal income tax return adjustments and permanent differences relating to book depletion and Medicare subsidy.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Operating Income

Operating Income increased by $1 million primarily due to:
o An $11 million increase in retail base revenues due to an increased number of customers and their average usage, offset in part by milder weather. Heating and Cooling degree-days decreased 7%.
o A $9 million refund of capacity payments not recoverable through the fuel clause for prior periods for purchased power.

The increase in Operating Income was partially offset by:

o A $10 million increase in Other Operation expenses primarily related to a prior year true-up for OATT transmission recorded in 2004 resulting from revised data from ERCOT for the years 2001-2003 offset in part by the sale of emission allowances.
o An $8 million increase in Depreciation and Amortization expenses primarily due to the amortization of a regulatory asset for the

recovery of fuel related costs in Arkansas and adjustments to excess earnings accruals per the Texas Legislation (see "Texas Restructuring" in Note 4).
o A $7 million increase in Maintenance expenses primarily due to scheduled power plant maintenance, as well as increased overhead line maintenance, partly due to increased storm damage.
o A $5 million decrease in margins from risk management activities.
o A $4 million increase in provision for rate refund primarily due to a wholesale fuel refund.
o A $3 million increase in Taxes Other Than Income Taxes primarily due to higher property taxes and state and local franchise taxes.
o A $2 million decrease in the portion of margin the company retains from off- system sales primarily due to decreased realization of off-system sales.

Fuel and Purchased Power

For the nine month comparison, purchased power expense decreased primarily due to KWH purchases declining 1%, the cost per KWH declining 2% and decreased capacity purchases. Fuel expense also decreased 19% primarily due to lower KWH generation of 6% and lower cost per KWH of 10%.

Other Impacts on Earnings

Interest Charges decreased $7 million as a result of refinancing higher interest rate debt and notes payable to trust with lower interest rate debt and notes payable to trust.

Minority Interest loss of $2 million is a result of consolidating Sabine Mining Company (Sabine) effective July 1, 2003, due to implementation of FIN 46. We now record the depreciation, interest and other operating expenses of Sabine and eliminate Sabine's revenues against our fuel expenses. While there was no effect to net income as a result of consolidation, some individual income statement lines were affected.

The Cumulative Effect of Accounting Changes is due to a one-time after-tax impact of adopting SFAS 143 and EITF 02-3 in 2003.

Income Taxes

The effective tax rates for the first nine months of 2004 and 2003 were 31.4% and 35.0%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to federal income tax return adjustments and permanent differences relating to book depletion and Medicare subsidy.

Financial Condition

Credit Ratings

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

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

In July 2004, Standard and Poor's upgraded the credit rating of the First Mortgage Bonds from BBB to A- due to a change in rating methodology. The principal amount of First Mortgage Bonds currently outstanding is $96 million.

Cash Flow

Cash flows for the nine months ended September 30, 2004 and 2003 were as follows:

	2004	2003

	----	----
Cash and cash equivalents at beginning of period	$5,676	$-
	---------	---------
Cash flows from (used for):		
Operating activities	214,943	209,157
Investing activities	(63,557)	(81,126)
Financing activities	(153,738)	(117,234)
	---------	---------
Net increase (decrease) in cash and cash equivalents	(2,352)	10,797
	---------	---------
Cash and cash equivalents at end of period	$3,324	$10,797
	=========	=========

Operating Activities

Cash Flows From Operating Activities were $215 million primarily due to Net Income, Fuel, Materials and Supplies, Fuel Recovery and Taxes Accrued offset in part by Accounts Receivable, Net, Accounts Payable and Other Assets and Liabilities.

Investing Activities

Cash Flows Used for Investing Activities were primarily for construction projects for improved transmission and distribution service reliability. For the remainder of 2004, we expect our Construction Expenditures to be approximately $34 million.

Financing Activities

Cash Flows Used For Financing Activities were for retiring higher interest rate long-term debt with lower interest rate long-term debt and advances from affiliates.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2004 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contracts	$53,500	Variable	2019
Installment Purchase Contracts	41,135	Variable	2011
Notes Payable - Affiliates	50,000	4.45	2010

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contracts	$53,500	7.60	2019
Installment Purchase Contracts	12,290	6.90	2004
Installment Purchase Contracts	12,170	6.00	2008
Installment Purchase Contracts	17,125	8.20	2011
First Mortgage Bonds	80,000	6.875	2025
First Mortgage Bonds	40,000	7.75	2004
Notes Payable	5,122	4.47	2011
Notes Payable	2,250	Variable	2008

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report 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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$16,606
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(4,354)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(177)
Change in Fair Value Due to Valuation Methodology Changes (d)	62
Changes in Fair Value of Risk Management Contracts (e)	1,703
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	(1,946)
Total MTM Risk Management Contract Net Assets	11,894
Net Cash Flow Hedge Contracts (g)	(6,621)
Total MTM Risk Management Contract Net Assets at September 30, 2004	$5,273

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

(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 2004. 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 2004.

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

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

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

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

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of September 30, 2004

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Consolidated (b)
		(in thousands)	
Current Assets	$26,708	$348	$27,056
Non Current Assets	15,128	106	15,234
Total MTM Derivative Contract Assets	41,836	454	42,290
Current Liabilities	(22,851)	(6,071)	(28,922)
Non Current Liabilities	(7,091)	(1,004)	(8,095)
Total MTM Derivative Contract Liabilities	(29,942)	(7,075)	(37,017)
Total MTM Derivative Contract Net Assets (Liabilities)	$11,894	$(6,621)	$5,273

(a) Does not include Cash Flow Hedges.

(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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

- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of September 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$1,116	$(3,340)	$14	$1,058	$-	$-	$(1,152)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(2,265)	7,791	696	-	-	-	6,222
Prices Based on Models and Other Valuation Methods (b)	2	1,610	336	(89)	1,214	3,751	6,824
Total	$(1,147)	$6,061	$1,046	$969	$1,214	$3,751	$11,894

"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.

(a) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(b) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008. $1.5 million of this mark-to-market value is in 2009.

(c) Amounts exclude Cash Flow Hedges.

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

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

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

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2004

	Power	Interest Rate	Consolidated
		(in thousands)	
Beginning Balance December 31, 2003	$184	$-	$184
Changes in Fair Value (a)	(1,735)	-	(1,735)
Reclassifications from AOCI to Net Income (b)	(323)	(2,006)	(2,329)
Ending Balance September 30, 2004	$(1,874)	$(2,006)	$(3,880)

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(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,519 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Nine Months Ended September 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$156	$865	$402	$140	$304	$1,182	$495	$118

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $50 million and $57 million at September 30, 2004 and December 31, 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$315,482	$347,672	$780,661	$835,193
Sales to AEP Affiliates	14,888	13,950	54,597	63,013
TOTAL	330,370	361,622	835,258	898,206
OPERATING EXPENSES				
Fuel for Electric Generation	109,468	155,853	292,536	360,471
Purchased Electricity for Resale	18,958	6,567	20,884	29,499
Purchased Electricity from AEP Affiliates	6,685	10,055	21,105	35,706
Other Operation	45,628	43,091	140,168	129,702
Maintenance	15,350	15,959	55,009	47,707
Depreciation and Amortization	33,676	30,381	96,940	89,284
Taxes Other Than Income Taxes	16,544	16,517	48,259	45,558
Income Taxes	23,443	23,970	38,013	39,418
TOTAL	269,752	302,393	712,914	777,345
OPERATING INCOME	60,618	59,229	122,344	120,861
Nonoperating Income	704	1,364	2,899	2,711
Nonoperating Expenses	669	577	2,735	1,453
Nonoperating Income Tax Expense (Credit)	(398)	18	(1,295)	(37)
Interest Charges	12,944	16,981	41,034	48,058
Minority Interest	(898)	(836)	(2,592)	(836)
Income Before Cumulative Effect of Accounting Changes	47,209	42,181	80,177	73,262
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	-	8,517
NET INCOME	47,209	42,181	80,177	81,779
Preferred Stock Dividend Requirements	57	57	172	172
EARNINGS APPLICABLE TO COMMON STOCK	$47,152	$42,124	$80,005	$81,607

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

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$135,660	$245,003	$334,789	$(53,683)	$661,769
Common Stock Dividends			(54,596)		(54,596)
Preferred Stock Dividends			(172)		(172)
TOTAL					607,001
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
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
DECEMBER 31, 2003	$135,660	$245,003	$359,907	$(43,910)	$696,660
Common Stock Dividends			(45,000)		(45,000)
Preferred Stock Dividends			(172)		(172)
TOTAL					651,488
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(4,064)	(4,064)
Minimum Pension Liability				23,066	23,066
NET INCOME			80,177		80,177
TOTAL COMPREHENSIVE INCOME					99,179
SEPTEMBER 30, 2004	$135,660	$245,003	$394,912	$(24,908)	$750,667

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,660,575	$1,622,498
Transmission	631,169	615,158
Distribution	1,110,441	1,078,368
General	443,001	423,427
Construction Work in Progress	33,651	60,009
TOTAL	3,878,837	3,799,460
Accumulated Depreciation and Amortization	1,700,023	1,617,846
TOTAL - NET	2,178,814	2,181,614
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	4,050	3,808
Other Investments	4,675	4,710
TOTAL	8,725	8,518
CURRENT ASSETS		
Cash and Cash Equivalents	3,324	5,676
Other Cash Deposits	5,243	6,048
Advances to Affiliates	95,026	66,476
Accounts Receivable:		
Customers	39,881	41,474
Affiliated Companies	19,112	10,394
Miscellaneous	7,849	4,682
Allowance for Uncollectible Accounts	(2,573)	(2,093)
Fuel Inventory	48,242	63,881
Materials and Supplies	34,928	33,775
Regulatory Asset for Under-recovered Fuel Costs	3,778	11,394
Risk Management Assets	27,056	19,715
Margin Deposits	2,063	5,123
Prepayments and Other	19,197	19,078
TOTAL	303,126	285,623
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	6,475	3,235
Unamortized Loss on Reacquired Debt	21,463	19,331
Minimum Pension Liability	35,487	-
Other	18,638	15,859
Long-term Risk Management Assets	15,234	12,178
Deferred Charges	61,081	55,605
TOTAL	158,378	106,208
TOTAL ASSETS	$2,649,043	$2,581,963

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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
Retained Earnings	394,912	359,907
Accumulated Other Comprehensive Income (Loss)	(24,908)	(43,910)
Total Common Shareholder's Equity	750,667	696,660
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700
Total Shareholders' Equity	755,367	701,360
Long-term Debt:		
Nonaffiliated	547,160	741,594
Affiliated	50,000	-
Total Long-term Debt	597,160	741,594
TOTAL	1,352,527	1,442,954
Minority Interest	1,043	1,367
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	209,974	142,714
Accounts Payable:		
General	27,336	37,646
Affiliated Companies	25,061	35,138
Customer Deposits	32,133	24,260
Taxes Accrued	92,231	28,691
Interest Accrued	11,967	16,852
Risk Management Liabilities	28,922	11,361
Obligations Under Capital Leases	3,695	3,159
Regulatory Liability for Over-recovered Fuel	8,866	4,178
Other	36,060	53,753
TOTAL	476,245	357,752
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	355,368	349,064
Long-term Risk Management Liabilities	8,095	4,667
Reclamation Reserve	7,740	16,512
Regulatory Liabilities:		
Asset Removal Costs	248,686	236,409
Deferred Investment Tax Credits	36,620	39,864
Excess Earnings	3,167	2,600
Other	17,868	18,779
Asset Retirement Obligations	27,043	8,429
Obligations Under Capital Leases	31,302	18,383
Deferred Credits and Other	83,339	85,183
TOTAL	819,228	779,890
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,649,043	$2,581,963

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$80,177	$81,779
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(8,517)
Depreciation and Amortization	96,940	89,284
Deferred Income Taxes	(7,303)	421
Deferred Investment Tax Credits	(3,244)	(3,245)
Deferred Property Taxes	(9,687)	(9,315)
Mark-to-Market of Risk Management Contracts	4,712	(11,497)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(9,812)	(8,862)
Fuel, Materials and Supplies	14,486	10,095
Accounts Payable	(20,387)	(18,773)
Taxes Accrued	63,540	42,396
Fuel Recovery	12,304	(13,750)
Change in Other Assets	(4,163)	(1,901)
Change in Other Liabilities	(2,620)	61,042
Net Cash Flows From Operating Activities	214,943	209,157
INVESTING ACTIVITIES		
Construction Expenditures	(68,238)	(86,488)
Proceeds from Sale of Assets and Other	3,876	9,085
Change in Other Cash Deposits, Net	805	(3,723)
Net Cash Flows Used For Investing Activities	(63,557)	(81,126)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	92,441	143,041
Issuance of Long-term Debt - Affiliated	50,000	-
Retirement of Long-term Debt	(222,457)	(58,478)
Change in Advances to/from Affiliates, Net	(28,550)	(147,029)
Dividends Paid on Common Stock	(45,000)	(54,596)
Dividends Paid on Cumulative Preferred Stock	(172)	(172)
Net Cash Flows Used For Financing Activities	(153,738)	(117,234)
Net Increase (Decrease) in Cash and Cash Equivalents	(2,352)	10,797
Cash and Cash Equivalents at Beginning of Period	5,676	-
Cash and Cash Equivalents at End of Period	$3,324	$10,797

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $40,136,000 and $45,211,000 and for income taxes was $11,326,000 and $26,166,000 in 2004 and 2003, respectively. Noncash acquisitions under capital leases were $14,226,000 in 2004. There were no noncash capital lease acquisitions in 2003.

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to SWEPCo's consolidated financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to SWEPCo.

NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to financial statements that follow are a combined presentation for AEP's registrant subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Significant Accounting Matters	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements	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.	Dispositions and Assets Held for Sale	TCC
8.	Benefit Plans	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
9.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Financing Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited interim financial statements should be read in conjunction with the 2003 Annual Report as incorporated in and filed with our 2003 Form 10-K.

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

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheet in the equity section. The components of Accumulated Other Comprehensive Income (Loss) for AEP registrant subsidiaries is shown in the following table.

Components	September 30, 2004	December 31, 2003
	(in thousands)	
Cash Flow Hedges:		
APCo	$(15,935)	$(1,569)
CSPCo	(2,115)	202
I&M	(8,543)	222
KPCo	(585)	420
OPCo	(3,483)	(103)
PSO	(2,323)	156
SWEPCo	(3,880)	184
TCC	(6,958)	(1,828)
TNC	(2,421)	(601)
Minimum Pension Liability:		
APCo	$(50,519)	$(50,519)
CSPCo	(46,529)	(46,529)
I&M	(25,328)	(25,328)
KPCo	(6,633)	(6,633)
OPCo	(52,646)	(48,704)
PSO	(43,998)	(43,998)
SWEPCo	(21,028)	(44,094)
TCC	(63,515)	(60,044)
TNC	(26,117)	(26,117)

During the first quarter of 2004, SWEPCo reclassified $23 million from Accumulated Other Comprehensive Income (Loss) related to minimum pension liability to Regulatory Assets ($35 million) and Deferred Income Taxes ($12 million) as a result of authoritative letters issued by the FERC and the Arkansas and Louisiana commissions.

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.

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, 2004	Accretion	Liabilities Incurred	Liabilities Settled	Balance at September 30, 2004
AEGCo (a)	$1.1	$0.1	$-	$-	$1.2
APCo (a)	21.7	1.3	-	(0.4)	22.6
CSPCo (a)	8.7	0.6	-	-	9.3
I&M (b)	553.2	29.6	-	-	582.8
OPCo (a)	42.7	2.5	-	-	45.2
SWEPCo (c)	8.4	0.9	17.7	-	27.0
TCC (d)	218.8	12.4	-	-	231.2

(a) Consists of asset retirement obligations related to ash ponds.
(b) Consists of asset retirement obligations related to ash ponds ($1.2 million at September 30, 2004) and nuclear decommissioning costs for the Cook Plant ($581.6 million at September 30, 2004).
(c) Consists of asset retirement obligations related to Sabine Mining and Dolet Hills.
(d) Consists of asset retirement obligations related to nuclear decommissioning costs for STP included in Liabilities Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

Accretion expense is included in Other Operation expense in the respective income statements of the individual subsidiary registrants.

As of September 30, 2004 and December 31 2003, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $902 million ($768 million for I&M and $134 million for TCC) and $845 million ($720 million for I&M and $125 million for TCC), respectively, recorded in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&M's Consolidated Balance Sheets and in Assets Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

Reclassification

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

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC implemented FASB Staff Position (FSP) FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," effective April 1, 2004, retroactive to January 1, 2004. The new disclosure standard provides authoritative guidance on the accounting for any effects of the Medicare prescription drug subsidy under the Act. It replaces the earlier FSP FAS 106-1, under which APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC previously elected to defer accounting for any effects of the Act until the FASB issued authoritative guidance on the accounting for the Medicare subsidy.

Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106's 10 percent corridor. The Medicare subsidy reduced the FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million. The tax-free subsidy reduced AEP's 2004 year-to-date net periodic postretirement benefit cost, after adjustment to capitalization of employee benefits costs as of a cost of construction, by a total of $20 million.

The following table provides the reduction in the net periodic postretirement benefit cost for the nine months ended September 30, 2004 for the AEP registrant subsidiaries:

	Postretirement Benefit Cost Reduction
	(in thousands)
APCo	$3,146
CSPCo	1,575
I&M	2,267
KPCo	466
OPCo	2,697
PSO	1,041
SWEPCo	1,076
TCC	1,251
TNC	528

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes. The FASB is currently working on several projects including discontinued operations, business combinations, liabilities and equity, revenue recognition, accounting for share-based compensation, pension plans, asset retirement obligations, earnings per share calculations, fair value measurements, accounting changes and related tax impacts. We also expect to see more FASB projects as a result of their desire to converge International Accounting Standards with those generally accepted in the United States of America. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

3. RATE MATTERS

As discussed in our 2003 Annual Report, rate and regulatory proceedings at the FERC and at several state commissions are ongoing. The Rate Matters note within our 2003 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material rate matters still pending, without significant changes since year-end. The following sections discuss current activities.

TNC Fuel Reconciliation - Affecting TNC

In 2002, TNC filed with the PUCT to reconcile fuel costs, requesting to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the True-up Proceeding. This reconciliation for the period from July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory.

In March 2003, the ALJ in this proceeding filed a Proposal for Decision (PFD) with a recommendation that TNC's under-recovered retail fuel balance be reduced. In March 2003, TNC established a provision for probable disallowance of $13 million based on the recommendations in the PFD. In May 2003, the PUCT reversed the ALJ on certain matters and remanded TNC's final fuel reconciliation to the ALJ to consider two issues: (1) the sharing of off-system sales margins from AEP's trading activities with customers for five years per the PUCT's interpretation of the Texas AEP/CSW merger settlement and (2) the inclusion of January 2002 fuel factor revenues and associated costs in the determination of the under-recovery. The PUCT proposed that the sharing of off-system sales margins for periods beyond the termination of the fuel factor should be recognized in the final fuel reconciliation proceeding. This would result in the sharing of margins for an additional three and one-half years after the end of the Texas ERCOT fuel factor. While management believes that the Texas merger settlement only provided for sharing of margins during the period fuel and generation costs were regulated by the PUCT, an additional provision of $10 million was recorded in December 2003.

In December 2003, the ALJ issued a PFD in the remand phase of the TNC fuel reconciliation recommending additional disallowances for the two remand issues. TNC filed responses to the PFD, and the PUCT announced a final ruling in the fuel reconciliation proceeding in January 2004 accepting the PFD. TNC received a written order in March 2004 and increased its provision by $1.5 million. In March 2004, various parties, including TNC, requested a rehearing of the PUCT's ruling. In May 2004, the PUCT reversed its position on the inclusion of MTM amounts in the allocation of system sales margins and remanded the case to the ALJ. As a result, TNC recorded an additional provision of $12 million in the second quarter of 2004 resulting in a provision for an over-recovery balance of approximately $7 million.

On July 2, 2004, the parties to the MTM remand proceeding filed a "Stipulation of Fact" in which all parties agreed to the quantification of the remanded issue. With the amounts included in the "Stipulation of Fact," the over-recovery balance would be $4 million. On October 13, 2004 the PUCT approved an order which included the amounts contained in the "Stipulation of Fact." The PUCT issued an order in the fuel reconciliation which reflected the "Stipulation of Fact" in October 2004. TNC will seek rehearing of the PUCT's order regarding issues other than the issue covered by the stipulation. TNC may appeal to the Texas District Court the PUCT's decision once all motions for rehearing have been adjudicated. Management expects to adjust its provision to an over-recovery balance of $4 million when it receives a final order in the fourth quarter 2004. Although management believes it has adequately provided for probable disallowances, a final order from the PUCT disallowing amounts in excess of the established provision could have a material adverse impact on TNC's future results of operations and cash flows.

In February 2002, TNC received a final order from the PUCT in a previous fuel reconciliation covering the period July 1997 through 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 was appealed by certain cities (the Cities) to the Third Court of Appeals. The Third Court of Appeals issued a ruling on September 23, 2004 upholding the District Court and the PUCT's final order. It is unknown at this time if the Cities will appeal to the Texas Supreme Court or if the court will hear the issue if they do.

TCC Fuel Reconciliation - Affecting TCC

In 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the True-up Proceeding. This reconciliation covers the period from July 1998 through December 2001.

Based on the PUCT ruling in the TNC proceeding related to similar issues, TCC established a provision for probable adverse rulings of $81 million during 2003. On February 3, 2004, the ALJ issued a PFD in the TCC case recommending that the PUCT disallow $140 million in eligible fuel costs including some new items not considered in the TNC case, and other items considered but not disallowed in the TNC ruling. Based on an analysis of the ALJ's recommendations and the initial final order in the TNC fuel reconciliation, TCC established an additional provision of $13 million during the first quarter of 2004. In May 2004, the PUCT accepted most of the ALJ's recommendations in the TCC case, however, the PUCT rejected the ALJ's recommendation to impute capacity to certain energy-only purchased power contracts and remanded the issue to the ALJ to determine if any energy-only purchased power contracts during the reconciliation period include a capacity component that is not recoverable in fuel revenues. In testimony filed in the remand proceeding, TCC has asserted that its energy-only purchased power contracts do not include any capacity component. Intervenors, including the Office of Public Utility Counsel, have filed testimony recommending that $15 million to $30 million of TCC's purchased power costs reflect capacity costs which are not recoverable in the fuel reconciliations. Hearings were held in October 2004 on this remand issue. As a result of the PUCT's acceptance of most of the ALJ's recommendations in TCC's case and the PUCT's remand decision in the TNC case regarding the inclusion of MTM amounts in the allocation of AEP's net system sales margins, TCC increased its provision by $47 million in the second quarter of 2004. The over-recovery balance and the provisions for probable disallowances totaled $210 million including interest at September 30, 2004.

At this time, management is unable to predict the outcome of this proceeding. Management believes it has provided for all probable to-date disallowances pending receipt of a final order. A final order has not yet been issued in TCC's final fuel reconciliation. Management will continue to challenge adverse decisions vigorously, including appeals if necessary. An order from the PUCT, disallowing amounts in excess of the established provision, couldhave a material adverse effect on TCC's future results of operations and cash flows. Additional information regarding the 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 in the SPP. This reconciliation covers the period from January 2000 through December 2002. During the reconciliation period, SWEPCo incurred $435 million of Texas retail eligible fuel expense. In November 2003, intervenors and the PUCT Staff recommended fuel cost disallowances of more than $30 million. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation. The settlement provides for a disallowance in fuel costs of $8 million which was recorded in December 2003. In April 2004, the PUCT approved the settlement.

Virginia Fuel Factor Filing - Affecting APCo

On October 29, 2004 APCo filed with the Virginia SCC to increase its fuel factor effective January 1, 2005. The requested factor is estimated to increase revenues by approximately $19 million on an annual basis. This increase reflects a continuing rise in the projected cost of coal in 2005. This fuel factor adjustment will increase 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.

TCC Rate Case - Affecting TCC

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

In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCC's requested $67 million rate increase. The recommendations ranged from a decrease in existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. Hearings were held in March 2004. In May 2004, TCC agreed to a non-unanimous settlement on cost of capital including capital structure and return on equity with all but two parties in the proceeding. TCC agreed that the return on equity should be established at 10.125% based upon a capital structure with 40% equity resulting in a weighted cost of capital of 7.475%. The settlement and other agreed adjustments reduced TCC's rate request from $67 million to $41 million. The ALJs that heard the case issued their recommendations on July 2, 2004, including a recommendation to approve the cost of capital settlement. The ALJs recommended that an issue related to the allocation of consolidated tax savings to the transmission and distribution utility be remanded for additional evidence. On July 15, 2004, the PUCT remanded this issue to the ALJs. On August 19, 2004, in a separate ruling the PUCT remanded six other issues to the ALJs requesting revisions to clarify and further support the recommendations in the PFD. In addition, the PUCT ordered TCC to calculate its revenue requirements based upon the recommendations of the ALJs. On July 21, 2004, TCC filed its revenue requirements based upon the recommendations of the ALJs. According to TCC's calculations, the ALJs' recommendations reduce TCC's existing rates by somewhere between $33 million and $43 million depending on the final resolution of the amount of consolidated tax savings. Hearings were held on the consolidated tax savings remand issue in September. The PUCT is expected to issue its decision by the end of 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates, revenues, results of operations, cash flows and financial condition.

On September 2, 2004, a group of intervenors, with subsequent support of the PUCT Staff, filed a request that a $30 million temporary, or interim, rate reduction be ordered subject to refund or surcharge. On September 24, 2004 the PUCT issued an order denying the motion for reduced temporary rates.

Louisiana Compliance Filing - Affecting SWEPCo

In October 2002, SWEPCo filed with the Louisiana Public Service Commission (LPSC) detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid-2005. In April 2004, SWEPCo filed updated financial information with a test year ending December 31, 2003 as required by the LPSC. Both filings indicated that SWEPCo's current rates should not be reduced. Subsequently, direct testimony was filed on behalf of the LPSC recommending a $15.4 million reduction in SWEPCo's Louisiana jurisdictional base rates. SWEPCo's rebuttal testimony is due December 15, 2004. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ordered in the future, it would adversely impact SWEPCo's results of operations and cash flows.

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 overcharged them for fuel costs since 1975. The LPSC consolidated the customer complaint and audit. A status conference is scheduled for December 16, 2004 to schedule a hearing date. Although management believes that SWEPCo's fuel costs were proper and fuel costs incurred prior to 1999 were approved by the LPSC, we are unable to predict the outcome of these proceedings. If the actions of the LPSC or the Court result in a material disallowance of SWEPCo's fuel recoveries, it would have an adverse impact on results of operations and cash flows. The LPSC Staff consultant made recommendations to reduce recoverable fuel expense from SWEPCo's Louisiana retail customers. The consultant recommended that SWEPCo be required to refund $3.9 million (through December 2002) stating the amount should be recovered through base rates versus the fuel factor. An additional amount of $1.4 million for the period of January 2003 through September 2004 would also be required to be refunded. In addition, the LPSC Staff contends that SWEPCo's Pirkey Power Plant experienced poor performance during the years 1999, 2001 and 2002 and that the incremental cost of replacement power should be refunded. The consultant did not provide an amount associated with this recommendation, but management believes that the amount could be material. If the LPSC adopts any of the consultant's recommendations, it would adversely impact SWEPCo's results of operations and cash flows.

PSO Fuel and Purchased Power - Affecting PSO

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West electric operating companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the Corporation Commission of the State of Oklahoma (OCC) seeking to recover these reallocated costs over a period of 18 months. In August 2003, the OCC Staff filed testimony recommending PSO be granted recovery of $42.4 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed testimony in February 2004. An intervenor and the OCC Staff filed testimony in April 2004. The intervenor suggested that $8.8 million related to the 2002 reallocation not be recovered from customers. The Attorney General of Oklahoma also filed a statement of position, indicating allocated off-system sales margins between and among AEP operating companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and if corrected could more than offset the $44 million 2002 reallocation under-recovery. The intervenor and the OCC Staff also believed off-system sales margins were allocated incorrectly and that a reallocation by the intervenors of such margins would reduce PSO's recoverable fuel by an additional $6.8 million for 2000 and $10.7 million for 2001, while under the OCC Staff method, the reduction for 2001 would be $8.8 million. The intervenor and the OCC Staff also recommend recalculation of fuel for years subsequent to 2001 using the same revised methods. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were under the jurisdiction of the OCC because they relate to FERC-approved allocation agreements. As a result, the ALJ ordered that the parties brief the jurisdictional issue. PSO filed its brief on September 1, 2004. Subject to the OCC's decision as to jurisdiction, a hearing date has been set for January 2005. Management believes that fuel costs have been prudently incurred consistent with OCC rules, and that the allocation of off-system sales margins was made pursuant to the FERC-approved allocation agreements. If the OCC determines that a portion of PSO's unrecovered fuel and purchased power costs should not be recovered, there will be, subject to the FERC jurisdictional question, an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

PSO Rate Review - Affecting PSO

In February 2003, the OCC filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003 and June 2004, PSO filed financial information and supporting testimony in response to the OCC's requirements. PSO's response indicates that its annual revenues are $41 million less than costs. As a result, PSO is seeking OCC approval to increase its base rates by that amount, which is a 3.9% increase over PSO's existing revenues. Hearings are scheduled to begin in February 2005 to address cost of service, fuel procurement and resource planning issues.

On August 12, 2004, PSO filed a motion to amend the schedule to consider new service quality and reliability requirements which took effect on July 1, 2004. On August 30, 2004, the OCC approved a revised schedule. On October 4, 2004, PSO filed supplemental information requesting consideration of approximately $55 million of additional annual operations and maintenance expenses and annual capital costs to enhance system reliability. On November 4, 2004, PSO filed a plan with the OCC seeking interim rate relief to fund a portion of the costs to meet the new state service quality and reliability requirements pending the outcome of the current case. In the filing, PSO seeks interim approval to collect incremental distribution tree trimming costs of approximately $29 million from its customers. The OCC Staff and intervenors are scheduled to file testimony regarding their recommendations on revenue requirement, fuel procurement, resource planning and vegetation management in December 2004. Rebuttal testimony is to be filed in January 2005 with hearings beginning in February 2005. A decision is not expected until second quarter 2005. Management is unable to predict the ultimate effect of these proceedings on PSO's revenues, results of operations, cash flows and financial condition.

RTO Formation/Integration - Affecting APCo, CSPCo, I&M, KPCo, and OPCo

Based on FERC approvals in response to non-affiliated companies' requests to defer RTO formation costs, the AEP East companies deferred costs incurred under FERC orders to originally form a new RTO (the Alliance RTO) or subsequently to join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both Alliance RTO formation costs and PJM integration costs including the deferral of a carrying charge thereon. The AEP East companies have deferred approximately $35 million of RTO formation and integration costs and related carrying charges through September 30, 2004. Amounts per company are as follows.

Company	(in millions)

APCo	$9.8
CSPCo	4.1
I&M	7.6
KPCo	2.3
OPCo	10.9

As a result of the subsequent delay in the integration of AEP's East transmission system into PJM, the FERC declined to rule, in its July 2003 order, on our request to transfer the deferrals to regulatory assets, and to maintain such deferrals until such time as the costs can be recovered from all users of AEP's East transmission system.

In its July 2003 order, the FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the open access transmission tariff (OATT) to be charged by PJM. Management believes that the FERC will grant permission for prudently incurred deferred RTO formation/integration costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of the AEP East companies' portion of the OATT as these companies file rate cases. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo and OPCo until 2006 and I&M until 2005.

In August 2004, we filed an application with the FERC dividing the RTO formation/integration costs between PJM-billed integration costs including related carrying charges, and all other RTO formation/integration costs. We intend to file with the FERC to request that deferred PJM-billed integration costs be recovered. The AEP East companies will be responsible for paying the amount allocated by the FERC to the AEP zone since it will be attributable to their internal load. In our August 2004 application, we requested permission to amortize approximately one-half of the deferred costs within the AEP zone over fifteen years beginning on January 1, 2005. We also requested to begin amortizing the deferred PJM-billed integration costs on January 1, 2005, but we did not propose an amortization period in the application.

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

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

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

In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. The order was based on PURPA 205(a), which allows the FERC to exempt electric utilities from state law or regulation in certain circumstances. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the exceptions under PURPA 205(a) apply. The FERC ALJ affirmed the FERC's preliminary findings in March 2004. The FERC issued an order related to this matter in June 2004 affirming its preliminary findings. In September 2004, Virginia filed an offer of settlement with the FERC in which they agreed to cease all attempts to obtain judicial relief from the June 2004 order on the condition that the FERC vacate the order. The FERC has not ruled on Virginia's settlement offer.

The AEP East companies integrated into PJM on October 1, 2004. The AEP East state regulatory Commissions have approved our integration with PJM and FERC has ordered us to defer our RTO formation/integration costs. Such costs will be recovered on an amortization basis through an OATT tariff charged to users of the system. The AEP East companies will also be charged by PJM for use of the system. AEP plans to seek recovery for the portion of the deferred RTO costs that are billed to the AEP East companies by PJM in future rate proceedings. The AEP East companies will expense their portion of the costs billed by PJM. Management is unable to predict whether the FERC will grant a long enough amortization period to allow for the opportunity for recovery of the non-PJM billed deferred RTO formation/integration costs in the AEP East state retail jurisdictions, and whether the state regulatory

Commissions will ultimately permit recovery of such costs billed to the AEP East companies by PJM. If the FERC ultimately decides not to approve an amortization period that would provide us with the opportunity to include such costs in future retail rate filings or the FERC or the state commissions deny recovery of our share of these costs, future results of operations and cash flows could be adversely affected.

FERC Order on Regional Through and Out Rates - Affecting APCo, CSPCo, I&M, KPCo and OPCo

In July 2003, the FERC issued an order directing PJM and the Midwest Independent System Operator (ISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and expanded PJM regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs' revenue distribution protocols. The order provided that affected transmission owners could file to offset the elimination of these revenues by increasing rates or utilizing a transitional rate mechanism to recover lost revenues that result from the elimination of the T&O rates. The FERC also found that the T&O rates of certain other companies that were then planning to join either PJM or Midwest Independent System Operator (MISO) ("Former Alliance RTO Participants"), including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the Combined Footprint. The FERC also initiated an investigation and hearing in regard to these rates.

In November 2003, the FERC issued an order finding that the T&O rates of the Former Alliance RTO Participants should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and Former Alliance RTO Participants, including AEP, to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004. The FERC was expected to implement a new rate design after the two-year period. As required by the FERC, AEP filed compliance tariff changes in January 2004 to eliminate the T&O charges within the Combined Footprint. Various parties raised issues with the SECA rate orders and the FERC implemented settlement procedures before an ALJ.

In April 2004, the FERC approved a settlement that delayed elimination of T&O rates until December 1, 2004 and provided principles and procedures for development of a new rate design for the Combined Footprint, to be effective on December 1, 2004. The settlement also provides that if the process did not result in the implementation of a new rate design on December 1, then the SECA rates will be implemented and will remain in effect until a new rate is implemented by the FERC. If implemented, the SECA rate would not be effective beyond March 31, 2006.

On September 16, 2004 the FERC Chief ALJ, acting as Settlement Judge, reported to the FERC that attempts to settle the issues had failed, and at least two competing long-term rate design proposals for the Combined Footprint were filed on October 1, 2004. AEP and several other utilities in the Combined Footprint have filed a proposal for new rates to become effective December 1, 2004.

The AEP East companies received approximately $157 million of T&O rate revenues for the twelve months ended December 31, 2003. At this time, management is unable to predict whether the rate design approved by the FERC will fully compensate the AEP East companies for their lost T&O revenues and whether any resultant increase in rates applicable to AEP's internal load will be recoverable on a timely basis from state retail customers. Unless new replacement rates compensate AEP for its lost revenues and any increase in AEP East Companies' transmission expenses from these new rates are fully recovered in retail rates on a timely basis, future results of operations, cash flows and financial condition will be adversely affected.

Indiana Fuel Order - Affecting I&M

On August 27, 2003, the IURC ordered that certain parties must negotiate the appropriate action on I&M's fuel cost recovery beginning March 1, 2004, following the February 2004 expiration of a fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant outage issues). The fixed fuel adjustment charge capped fuel recoveries. In an agreement in connection with AEP's planned corporate separation, I&M agreed, contingent on AEP implementing the corporate separation, to a fixed fuel adjustment charge beginning March 2004 and continuing through December 2007. Although AEP has not corporately separated, certain parties believe the fixed fuel adjustment charge should continue beyond February 2004. Negotiations with the parties to resolve this issue are ongoing. The IURC ordered that the fixed fuel adjustment charge remain in place, on an interim basis, in March and April 2004.

In April 2004, the IURC issued an order that extended the interim fuel factor for May through September 2004, subject to true-up to actual fuel costs following the resolution of the issue regarding the corporate separation agreement. The IURC also issued an order that reopened the corporate separation docket to investigate issues related to the corporate separation agreement. In July 2004, I&M filed for approval of a fuel factor for the period October 2004 through March 2005. On September 22, 2004, the IURC issued an order extending the interim fuel factor for October 2004 through March 2005, subject to true-up upon resolution of the corporation separation issues. At September 30, 2004, I&M has over-recovered its fuel costs and has recorded a regulatory liability to refund such over-recovery. However, if I&M's position should shift to a net under-recovery, the fixed fuel adjustment factor, capping the fuel revenues, could adversely affect its results of operations and cash flows if recovery is denied by the IURC.

Michigan 2004 Fuel Recovery Plan - Affecting I&M

A 1999 Michigan Public Service Commission (MPSC) order approved a Settlement Agreement regarding the extended outage of the Cook Plant and fixed I&M's Power Supply Cost Recovery (PSCR) factors for the St. Joseph and Three Rivers rate areas through December 2003. As required, I&M filed its 2004 PSCR Plan with the MPSC on September 30, 2003 seeking new fuel and power supply recovery factors to be effective in 2004. A public hearing was held on March 10, 2004. On June 4, 2004, the ALJ recommended that SO2 and NOx net credits be excluded from the fuel recovery mechanism. I&M filed its exceptions in June 2004. A MPSC order is expected during the fourth quarter of 2004. As allowed by Michigan law, the proposed factors were effective on January 1, 2004, subject to review by the MPSC and possible adjustment. When SO2 and NOx are a net cost exclusion from the fuel cost recovery mechanism, it will adversely affect I&M's future results of operations and cash flows. On September 30, 2004, I&M filed its 2005 PSCR Plan.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

As discussed in the 2003 Annual Report, certain AEP subsidiaries are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in the 2003 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant current events related to customer choice and industry restructuring.

OHIO RESTRUCTURING - Affecting CSPCo and OPCo

The Ohio Electric Restructuring Act of 1999 (Ohio Act) provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005. The Public Utilities Commission of Ohio (PUCO) may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utility's certified territory or that there is a twenty percent switching rate of the incumbent utility's load by customer class. Following the MDP, retail customers will receive cost-based regulated distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates.

On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rules provide for a Market Based Standard Service Offer (MBSSO) which would be a variable rate based on a transparent forward market, daily market, and/or hourly market prices. The rules also require a fixed-rate Competitive Bidding Process (CBP) for residential and small nonresidential customers and permits a fixed-rate CBP for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the MBSSO and the CBP. Customers who make no choice will be served pursuant to the CBP. The rules also required that electric distribution utilities file an application for MBSSO and CBP by July 1, 2004. CSPCo and OPCo were recently granted a waiver from making the required MBSSO/CBP filing, pending the outcome of a rate stabilization plan they filed with the PUCO in February 2004.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed rate stabilization plans with the PUCO addressing prices following the end of the MDP. If approved by the PUCO, prices would be established pursuant to CSPCo's and OPCo's plans for the period from January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. The plans include annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo) in 2006, 2007 and 2008 and the opportunity for additional generation-related increases upon PUCO review and approval. For residential customers, however, if the temporary 5% generation rate discount provided by the Ohio Act were eliminated prior to December 31, 2005 as permitted by the Ohio Act, the fixed increases would be adjusted downward to reflect the effect of such elimination. Additionally, the plan includes the opportunity to annually request an additional increase averaging 4% per year for both companies in the event costs run beyond the level currently anticipated. The plans would maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level effective on December 31, 2005. Such rates could be adjusted for specified reasons. Transmission charges could also be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion, and ancillary services. The plans also provide for continued amortization and recovery of stranded transition generation-related regulatory assets and for the deferral as regulatory assets in 2004 and 2005 of RTO costs and carrying charges on governmentally mandated, mainly environmental, capital expenditures. Hearings were held in June 2004 on the Companies' proposed rate stabilization plans. Briefs were submitted in July. The filings are pending before the PUCO.

The PUCO, in a recent order involving a non-affiliated company's rate stabilization plan, noted its reluctance to authorize automatic increases in any portion of rates and required a PUCO determination in the future prior to adjusting a rate component, instead of the automatic increases to the rate component which had been proposed. It also held that deferral during the MDP of certain expenses at issue in the case, for recovery after the MDP, would violate the rate cap under the Ohio Act. The PUCO has been asked in that case to reconsider these holdings and that request currently is pending. OPCo's and CSPCo's rate plans and the record in its cases are distinct from the rate plan and record considered by the PUCO in its recent order. In that regard, the PUCO has indicated in FirstEnergy companies' rate stabilization plans that these plans are specific to a company's requirements and characteristics and the PUCO's order in one case should not be considered precedent for another company's rate stabilization plan.

Management cannot predict whether CSPCo's and OPCo's plans will be approved as submitted nor can we predict the ultimate impact these proceedings will have on revenues, results of operations and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, we are deferring customer choice implementation costs and related carrying costs 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. Through September 30, 2004, CSPCo incurred $37 million and deferred $17 million and OPCo incurred $38 million and deferred $18 million for probable future recovery in distribution rates. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. If the rate stabilization plan is approved as filed, it would defer recovery of these amounts until the next distribution rate filing. Management believes that its deferred customer choice implementation costs were prudently incurred and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING - Affecting SWEPCo, TCC and TNC

Texas Legislation enacted in 1999 provides the framework and timetable to allow retail electricity competition for all Texas customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007. TCC and TNC operate in ERCOT while SWEPCo and a small portion of TNC's business is in SPP.

The Texas Legislation, among other things:
o provides for the recovery of stranded generation plant costs, generation-related regulatory assets and other generation true-up amounts through securitization and non-bypassable wires charges,
o requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility,
o provides for an earnings test for each of the years 1999 through 2001 and,
o provides for a stranded cost True-up Proceeding after January 10, 2004.

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

TEXAS TRUE-UP PROCEEDINGS

The True-up Proceedings will determine the amount and recovery of:
o stranded generation plant costs and generation-related regulatory assets including any unrefunded accumulated excess earnings (stranded generation costs),
o carrying charges on true-up amounts from January 1, 2002 (the commencement date of retail competition), a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up),
o final approved deferred fuel balance,
o excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
o and other true-up items.

The PUCT adopted a rule in 2003 regarding the timing of the True-up Proceedings scheduling TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later. TNC filed its true-up request in June 2004 and updated the filing in October 2004. Due to regulatory and contractual delays in the sale of its generating assets, TCC has not filed its true-up request.

True-up Net Regulatory Asset (Liability) Recorded at September 30, 2004:

TCC

	TCC	TNC
	---	---
	(in millions)	
Components of Net Stranded Generation Costs:		
Stranded Generation Plant Costs	$1,079	$-
Unsecuritized Transition Generation Regulatory Asset	249	-
Unrefunded Excess Earnings	(15)	-
Other	(56)	-
	-------	-----
Net Stranded Generation Costs	1,257	-
	-------	-----
Components of Other Recoverable True-up Amounts:		
Wholesale Capacity Auction True-up	480	-
Retail Clawback (a)	(60)	(14)
Deferred Over-recovered Fuel Balance	(210)	(7)
	-------	-----
Other Recoverable True-up Amounts	210	(21)
	-------	-----
Total Recorded Net True-up Regulatory Asset	$1,467	$(21)
	=======	=====

(a) Only half of these amounts are actually recorded as regulatory liabilities, as the other half are the responsibility of the unaffiliated company that owns the affiliated price-to-beat REP.

See discussion below of the above amounts.

Net Stranded Generation Costs

The Texas Restructuring Legislation required utilities with stranded generation plant costs to use market-based methods to value certain generation assets for determining stranded generation plant costs. TCC is the only AEP subsidiary that has stranded generation plant costs under the Texas Legislation. TCC elected to use the sale of assets method to determine the market value of TCC's generation assets for determining stranded generation plant costs. For purposes of the True-up Proceeding, the amount of stranded generation plant costs under this market valuation methodology will be the amount by which the book value of TCC's generation assets exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. Based on the prices established by the generation asset sales, discussed below, TCC recorded a net regulatory asset of $1.1 billion for its stranded generation plant costs from the sale of TCC's generation assets as shown in the table above, before accrual of any applicable carrying charges discussed below.

In June 2003, TCC began actively seeking buyers for 4,497 megawatts of their generation capacity in Texas. TCC received bids for all of their generation plants. In January 2004, TCC agreed to sell its 7.81% ownership interest in the Oklaunion Power Station to an unaffiliated third party for approximately $43 million. In March 2004, TCC agreed to sell its 25.2% ownership interest in STP for approximately $333 million and its other coal, gas and hydro plants for approximately $430 million to unaffiliated entities. Each sale is subject to specified price adjustments. TCC sent right of first refusal notices to the co-owners of Oklaunion and STP. TCC filed for FERC approval of the sales of Oklaunion, STP and the fossil and hydro plants. TCC received a notice from co-owners of Oklaunion and STP exercising their right of first refusal; therefore, SEC approval will be required. The original unaffiliated third party purchaser of Oklaunion has petitioned for a court order declaring its contract valid and the co-owners' rights of first refusal void. The sale of STP will also require approval from the Nuclear Regulatory Commission. On July 1, 2004, TCC completed the sale of the other coal, gas and hydro plants for approximately $425 million, net of adjustments. The closings of the sales of STP and Oklaunion plants are expected to occur in the first half of 2005, subject to clarification of the rights of first refusal and the necessary regulatory approvals. In addition, there could be delays in resolving litigation with a third party affecting Oklaunion. In order to sell these assets, TCC defeased all of its remaining outstanding first mortgage bonds in May 2004. In December 2003, TCC recognized as a regulatory asset an estimated impairment from the sale of their generation assets. TCC is considering seeking a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closings of the sales of all the generation assets.

In addition to its $1.1 billion of stranded generation plant costs, the Texas legislation permits TCC to recover its remaining unsecuritized net transition generation regulatory assets of $249 million less a regulatory liability for the unrefunded excess earnings of $15 million, discussed below. With other adjustments, TCC's recorded net stranded generation costs total $1.3 billion.

Unrefunded Excess Earnings

The Texas Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined by the PUCT for this three-year period were $3 million for SWEPCo, $47 million for TCC and $19 million for TNC. TCC, TNC and SWEPCo challenged the PUCT's treatment of fuel-related deferred income taxes and appealed the PUCT's final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. After appealing the District Court ruling upholding the PUCT decision, the Third Court of Appeals reversed the PUCT order and the District Court's judgment. The District Court remanded to the PUCT an appeal of the same issue from the PUCT's 2001 order upon agreement of the parties after issuance of the Third Court of Appeals decision. On September 14, 2004, the parties to the PUCT remand reached an agreement which changed the method for calculating excess earnings which, in turn, revised the calculation for 2000 and 2001 consistent with the ruling of the court. Revised excess earnings for the three-year period were approximately $3 million for SWEPCo, $42 million for TCC and $15 million for TNC. The PUCT issued a final order approving the agreement in October 2004. Since an expense and regulatory liability had been accrued in prior years in compliance with the PUCT orders, the companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Court's decision and credited amortization expense during the third quarter of 2003. Under the Texas legislation since TNC and SWEPCo do not have stranded generation plant cost, excess earnings have been applied to reduce T&D capital expenditures.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order had no additional effect on reported net income but reduces cash flows over the refund period. The remaining $15 million to be refunded is recorded as a regulatory liability at September 30, 2004 and can be included as a reduction to TCC's stranded generation plant costs. Management believes that TCC has stranded costs and that it was, therefore, inconsistent with the Texas restructuring legislation for the PUCT to order a refund prior to TCC's True-up Proceeding. TCC appealed the PUCT's premature refund of excess earnings to the Travis County District Court. That court affirmed the PUCT's decision and further ordered that the refunds be provided to ultimate customers. TCC has appealed the decision to the Third Court of Appeals.

Carrying Charges on Recoverable Stranded Costs

In December 2001, the PUCT issued a rule concerning stranded cost true-up proceedings stating, among other things, that carrying costs on stranded costs would begin to accrue on the date that the PUCT issued its final order in the True-up Proceeding. TCC and one other Texas electric utility company filed a direct appeal of the rule to the Texas Third Court of Appeals contending that carrying costs should commence on January 1, 2002, the day that retail customer choice began in ERCOT.

The Third Court of Appeals ruled against the utilities, who then appealed to the Texas Supreme Court. On June 18, 2004, the Texas Supreme Court reversed the decision of the Third Court of Appeals determining that a carrying cost should be accrued beginning January 1, 2002 and remanded the proceeding to the PUCT for further consideration. The Supreme Court determined that utilities with stranded costs are not permitted to over-recover stranded costs and the PUCT should address whether any portion of the 2002 and 2003 wholesale capacity auction true-up regulatory asset includes a recovery of stranded costs or carrying costs on stranded costs. A motion for rehearing with the Supreme Court was denied and the ruling is final.

The PUCT in September 2004 considered the Supreme Court's decision in true-up hearings held for another utility, CenterPoint Energy, Inc. (CenterPoint). In that case while the PUCT has indicated preliminary positions regarding the methodology to calculate recoverable carrying costs, uncertainties exist as to the ultimate methodology that will be adopted by the PUCT in its final order. The final order in the CenterPoint case is expected to be issued later in November 2004. If the final order in the CenterPoint case resolves the existing uncertainties, TCC will record a carrying cost back to January 1, 2002 in the fourth quarter of 2004 as an increase to its net true-up regulatory asset. At this time management is unable to determine the amount of such carrying cost pending receipt of the final CenterPoint order.

Wholesale Capacity Auction True-up

The Texas Legislation required that electric utilities and their affiliated power generation companies (PGC) offer for sale at auction, in 2002, 2003 and thereafter, 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 are used to calculate the wholesale capacity auction true-up revenues for the True-up Proceeding. According to PUCT rules, the wholesale capacity auction true-up is only applicable to the years 2002 and 2003. TCC recorded a $480 million regulatory asset and related revenues which represent the quantifiable amount of the wholesale capacity auction true-up for the years 2002 and 2003.

In the true-up proceeding of CenterPoint, while the PUCT has indicated preliminary positions regarding modifications of the calculation of the wholesale capacity auction true-up reflecting CenterPoint's specific facts and circumstances, uncertainties exist as to the ultimate modifications and calculations that will be adopted by the PUCT in its final order and if TCC's facts and circumstances will result in similar results in its true-up proceeding. Specifically, the PUCT is evaluating whether the amount of depreciation in the ECOM model on generation assets for 2002 and 2003 used to calculate the wholesale capacity auction true-up is a recovery of net stranded generation costs and should reduce the recoverable cost. The total TCC depreciation in the ECOM Model for the 2002-2003 period was $238 million. Upon issuance of a final written order in the CenterPoint case, management will evaluate the order and, if appropriate, record a provision for any amount that is no longer probable of recovery as a result of final decisions in the order which are applicable to TCC. The CenterPoint order is expected to be issued later in November 2004.

Retail Clawback

The Texas Legislation provides for the affiliated price-to-beat (PTB) retail electric providers (REPs) serving residential and small commercial customers to refund to its T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. During 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. The PUCT approved TCC's and TNC's filings in December 2003. In 2002, AEP had accrued a regulatory liability of approximately $9 million for the small commercial retail clawback on its REP's books. When the PUCT certified that the REP's in TCC and TNC service territories had reached the 40% threshold, the regulatory liability was no longer required for the small commercial class and was reversed in December 2003. Based upon customer information filed by the unaffiliated company which operates as the price-to-beat REP for TCC and TNC, we updated the estimated residential retail clawback regulatory liability in May 2004. At September 30, 2004, TCC's retail clawback regulatory liability was $30 million and TNC's was $7 million.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the True-up Proceeding. In January 2004, the PUCT announced a final ruling in TNC's fuel reconciliation case. The PUCT issued a written order in March 2004. Various parties, including TNC, requested rehearing of the PUCT's order. In May 2004, the PUCT reversed certain prior rulings which resulted in an over-recovered balance of $7 million. In October 2004, the PUCT issued a final order which resulted in a reduction in the over-recovery balance to $4 million. TNC filed an update to its true-up filing to reflect the PUCT's final order in October 2004.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery fuel balance for inclusion in the True-up Proceeding. In May 2004, the PUCT remanded TCC's fuel proceeding to the ALJ to consider additional evidence on one issue. TCC has provided for a $210 million over-recovery balance at September 30, 2004. Management believes that TCC has provided for all probable to-date disallowances pending the remand and receipt of a final order. However, due to the remand, management is unable to predict the amount of any additional disallowances of TCC's final fuel over-recovery balance which will be included in its True-up Proceeding until the remand is completed and a final order issued.

See TCC Fuel Reconciliation and TNC Fuel Reconciliation in Note 3 "Rate Matters" for further discussion.

Stranded Cost Recovery

When the True-up Proceeding is completed, TCC intends to file to recover PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying charges, through a non-bypassable competition transition charge in the regulated T&D rates. TCC intends to seek to securitize the approved net stranded generation costs plus related carrying costs. The annual costs of securitization are recovered through a non-bypassable transition charge collected by the T&D utility over the term of the securitization bonds. The other approved net true-up items will be recovered or refunded through a non-bypassable competition transition wires charge or credit.

TCC's recorded net regulatory asset for amounts subject to approval in the True-up Proceeding is approximately $1.5 billion at September 30, 2004. TCC expects that its True-up Proceeding filing will seek to recover an amount in excess of the total of its recorded net regulatory asset through September 30, 2004. This is primarily due to the fact that TCC has not been able to accrue a carrying cost to date as a result of uncertainties that exist. Management expects to be able to record a carrying cost in the fourth quarter of 2004 based on the final order in the CenterPoint case.

Due to the preliminary nature of the pending CenterPoint proceedings and the consequent uncertainty, differences between CenterPoint's and TCC's facts and circumstances and the lack of direct applicability of the CenterPoint proceeding to TCC's recorded assets, management cannot, at this time, determine whether disallowances that may be applicable to CenterPoint would be applicable to TCC. Management believes that TCC's recorded regulatory assets are in compliance with Texas Legislation and TCC intends to seek vigorously recovery of these amounts. If, however, management determines that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.5 billion and management is able to estimate the amount of such non-recovery, TCC will record a provision for such amount which could have a material adverse effect on future results of operations, cash flows and possibly financial condition. To the extent decisions in the TCC True-up Proceeding differ from management expectations based in part on management's evaluation of the final CenterPoint decision, additional material disallowances are possible.

TNC 2004 True-up Filing

In June 2004, TNC filed its True-up Proceeding including the fuel reconciliation balance and the retail clawback calculation. The amount of the deferred over recovered fuel balance recorded at September 30, 2004 was approximately $7 million. The retail clawback regulatory liability included in the filing was adjusted in the second quarter of 2004 to $7 million (TNC's allocated portion of the REPs' retail clawback) reflecting the number of customers served on January 1, 2004. TNC filed an update to the true-up filing to reflect the final order in its fuel reconciliation proceeding in October 2004 which adjusted its over-recovery balance to $4.7 million inclusive of interest.

VIRGINIA RESTRUCTURING - Affecting APCo

In April 2004, the Governor of Virginia signed legislation which extends the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within the 2003 Annual Report, certain AEP subsidiaries continue to be involved in various legal matters. The 2003 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since their disclosure in the 2003 Annual Report. The material matters discussed in the 2003 Annual Report without significant changes in status since year-end include, but are not limited to, (1) nuclear matters, (2) construction commitments, (3) potential uninsured losses, and (4) FERC proposed Standard Market Design. See disclosure below for significant matters with changes in status subsequent to the disclosure made in the 2003 Annual Report.

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation - Affecting APCo, CSPCo, I&M, and OPCo

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

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

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

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 was scheduled for July 2004, but has been postponed until January 2005 to facilitate further settlement negotiations.

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 the Federal EPA bears the burden of proof on the issue of whether a practice is "routine maintenance, repair, or replacement" and on whether or not a "significant net emissions increase" results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is "routine within the relevant source category" in determining if it is "routine." Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals, and the District Court denied the Federal EPA's motion. On April 13, 2004, the parties filed a joint motion for entry of final judgment, based on stipulations of relevant facts that obviated the need for a trial, but preserving plaintiffs' right to seek an appeal of the federal prevention of significant deterioration (PSD) claims. On April 14, 2004, the Court entered final judgment for Duke Energy on all of the PSD claims made in the amended complaints, and dismissed all remaining claims with prejudice. The United States subsequently filed a notice of appeal to the Fourth Circuit Court of Appeals. The case was briefed in September 2004.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for alleged CAA violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the CAA are unconstitutional. The United States filed a petition for certiorari with the United States Supreme Court and on May 3, 2004, that petition was denied.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which 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. Briefing continues in this case and oral argument is scheduled for January 2005.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines "routine maintenance repair and replacement" to include "functionally equivalent equipment replacement." Under the new 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 a prospective effect, and was to become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003 twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

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

In December 2000, Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

On July 21, 2004, the Sierra Club issued a notice of intent to file a citizen suit claim against DPL, Inc., Cinergy Corporation, CSPCo, and The Dayton Power & Light Company for alleged violations of the New Source Review programs at the Stuart Station. CSPCo owns a 26% share of the Stuart Station. On September 21, 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio state implementation plan occurred at the J.M. Stuart Station, and seeking injunctive relief and civil penalties. Management believes the allegations in the complaint are without merit, and intends to defend vigorously this action. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

SWEPCo Notice of Enforcement and Notice of Citizen Suit - Affecting SWEPCo

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the Clean Air Act for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. No action can be commenced until 60 days after the date of notice.

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

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On August 30, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the reporting of volatile organic compound emissions at the Pirkey Plant.

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

Carbon Dioxide Public Nuisance Claims - Affecting AEP System

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

Nuclear Decommissioning - Affecting TCC

As discussed in the 2003 Annual Report, decommissioning costs are accrued over the service life of STP. The licenses to operate the two nuclear units at STP expire in 2027 and 2028. TCC had estimated its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year.

In May 2004, an updated decommissioning study was completed for STP. The study estimates TCC's share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. TCC is currently analyzing the STP study to determine the effect on our asset retirement obligations (ARO) and will make any appropriate adjustments to the ARO liability and related regulatory asset in the fourth quarter 2004. As discussed in Note 7, TCC is in the process of selling its ownership interest in STP to a non-affiliate, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

OPERATIONAL

Power Generation Facility - Affecting OPCo

AEP has agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to AEP. AEP has subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004.

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

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

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

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

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

TEM, and Tractebel SA under the guaranty, damages and the full termination payment value of the PPA.

Merger Litigation - Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO,
SWEPCo, TCC and TNC

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In August 2004, the SEC announced it would conduct hearings on this issue. The hearing is scheduled for January 2005.

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUHCA's single region requirement. In its ruling, the appeals court said that the SEC failed to support and explain its conclusions that the interconnection and single region requirements are satisfied.

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

Enron Bankruptcy - Affecting APCo, CSPCo, I&M, KPCo and OPCo

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

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

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

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

Texas Commercial Energy, LLP Lawsuit - Affecting TCC and TNC

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

Energy Market Investigation - Affecting AEP System

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

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. AEP responded to the complaint in September 2004. In 2003, AEP recorded a provision related to these matters. AEP has engaged in settlement discussions with several agencies and is evaluating whether to conclude settlements in order to put these investigations behind us even though management believes it has meritorious legal positions and defenses. If management elects to settle all matters, the payment could exceed the 2003 provision and could have a material impact on our 2004 earnings and cash flows.

FERC Market Power Mitigation - Affecting AEP System

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. These two screening tests include a "pivotal supplier" test which determines if the market load can be fully served by alternative suppliers and a "market share" test which compares the amount of surplus generation at the time of the applicant's minimum load. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order and directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way.

On August 9, 2004, AEP submitted its Market Power Analysis pursuant to the FERC's Orders on Rehearing. The analysis focused on the three major areas in which AEP serves load and owns generation resources -- ECAR, SPP and ERCOT, and the "first tier" control areas for each of those areas.

The pivotal supplier and market share screen analyses that AEP filed demonstrated that AEP does not possess market power in any of the control areas to which it is directly connected (first-tier markets). AEP passed both screening tests in all of its "first tier" markets. In its three "home" control areas, AEP easily passed the pivotal supplier test. AEP, as part of PJM, also passes the market share screen for the PJM destination market. AEP also passed the market share screen for ERCOT. AEP did not pass the market share screen as designed by the FERC for the SPP control area. Consequently, AEP also submitted substantial additional information, including historical purchase and sales data that demonstrates that AEP does not possess market power in any of the "home" destination markets. AEP requested that its existing market-based pricing authorization in all markets be continued based on this analysis. AEP also requested that the FERC rule without instituting a proceeding and without setting a refund date. This case is pending.

6. GUARANTEES

There are no material liabilities recorded for guarantees in accordance with FIN 45. 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.

Letter of Credit

TCC has entered into a standby letter of credit (LOC) with third parties. This LOC covers credit enhancements for issued bonds. This LOC was issued in TCC's ordinary course of business. At September 30, 2004, the maximum future payments of the LOC are $43 million which matures November 2005. There is no recourse to third parties in the event this letter of credit is drawn.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $54 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, 2004, 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. Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine. SWEPCo does not have an ownership interest in Sabine.

Indemnifications and Other Guarantees

All of the registrant subsidiaries enter into certain types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Registrant subsidiaries cannot estimate the maximum potential exposure for any of these indemnifications entered into prior to December 31, 2002 due to the uncertainty of future events. In 2003 and during the first nine months of 2004, registrant subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual registrant subsidiary except for TCC which entered into an indemnification of $129 million relating to the sale of its generation assets in July 2004 (see Note 7). There are no material liabilities recorded for any indemnifications.

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

Certain registrant subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, 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, 2004, the maximum potential loss by subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Subsidiary	Maximum Potential Loss (in millions)
APCo	$ 5
CSPCo	2
I&M	3
KPCo	1
OPCo	4
PSO	4
SWEPCo	4
TCC	6
TNC	3

7. DISPOSITIONS AND ASSETS HELD FOR SALE

DISPOSITIONS COMPLETED DURING THIRD QUARTER 2004

Texas Plants - TCC Generation Assets

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as "reliability must run" status.

During the fourth quarter of 2003, after receiving indicative bids from interested buyers, TCC recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to Assets Held for Sale - Texas Generation Plants. In accordance with Texas legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the True-up Proceeding. As a result of the True-up Proceeding, if TCC is unable to recover all or a portion of its requested costs (see Note 4), any unrecovered costs could have a material adverse effect on TCC's results of operations, cash flows and possibly financial condition.

In March 2004, TCC signed an agreement to sell eight natural gas plants, one coal-fired plant and one hydro plant to a non-related joint venture. The sale was completed in July 2004 for approximately $425 million, net of adjustments. The sale did not have a significant effect on TCC's results of operations during the periods ending September 30, 2004.

DISPOSITIONS ANTICIPATED BEING COMPLETED DURING FIRST HALF 2005

Texas Plants - Oklaunion Power Station

In January 2004, TCC signed an agreement to sell its 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. In May 2004, TCC received notice from the two unaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal, with terms similar to the original agreement. In June 2004 and September 2004, TCC entered into sales agreements with both of its unaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. One of these agreements is currently being challenged in Dallas County, Texas State District Court by the unrelated party with which TCC entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners' exercise of their rights of first refusal void. TCC cannot predict when these issues will be resolved. TCC does not expect the sale to have a significant effect on its results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale - Texas Generation Plants and Liabilities Held for Sale - Texas Generation Plants, respectively, in TCC's Consolidated Balance Sheets at September 30, 2004 and December 31, 2003.

Texas Plants - South Texas Project

In February 2004, TCC signed an agreement to sell its 25.2% share of the South Texas Project (STP) nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, TCC received notice from co-owners of their decisions to exercise their rights of first refusal, with terms similar to the original agreement. In September 2004, TCC entered into sales agreements with two of its unaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. TCC does not expect the sale to have a significant effect on its results of operations. TCC expects the sale to close in the first six months of 2005. TCC's assets and liabilities related to STP have been classified as Assets Held for Sale - Texas Generation Plants and Liabilities Held for Sale - Texas Generation Plants, respectively, in TCC's Consolidated Balance Sheets at September 30, 2004 and December 31, 2003.

The assets and liabilities of the TCC plants held for sale at September 30, 2004 and December 31, 2003 are as follows:

	September 30, 2004	December 31, 2003
	(in millions)	
Assets:		
Other Current Assets	$24	$57
Property, Plant and Equipment, Net	398	797
Regulatory Assets	53	49
Decommissioning Trusts	134	125
Total Assets Held for Sale	$609	$1,028
Liabilities:		
Regulatory Liabilities	$1	$9
Asset Retirement Obligations	231	219
Total Liabilities Held for Sale	$232	$228

8. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees in the U.S.

The following tables provide the components of AEP's net periodic benefit cost (credit) for the plans for the three and nine months ended September 30, 2004 and 2003:

Three Months ended September 30, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in millions)			
Service Cost	$22	$20	$10	$10
Interest Cost	57	58	29	33
Expected Return on Plan Assets	(73)	(79)	(20)	(16)
Amortization of Transition (Asset) Obligation	-	(2)	7	7
Amortization of Net Actuarial Loss	4	3	9	13
Net Periodic Benefit Cost (Credit)	$10	$-	$35	$47

Nine Months ended September 30, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in millions)			
Service Cost	$65	$60	$30	$31
Interest Cost	171	175	88	98
Expected Return on Plan Assets	(219)	(238)	(61)	(48)
Amortization of Transition (Asset) Obligation	1	(6)	21	21
Amortization of Prior Service Cost	-	(1)	-	-
Amortization of Net Actuarial Loss	12	8	27	39
Net Periodic Benefit Cost (Credit)	$30	$(2)	$105	$141

The following table provides the net periodic benefit cost (credit) for the plans by the following AEP registrant subsidiaries for the three and nine months ended September 30, 2004 and 2003:

Three Months ended September 30, 2004 and 2003:

	U.S. Pension Plans	U.S. Other Postretirement Benefit Plans

	2004	2003	2004	2003
	(in thousands)			
APCo	$318	$(1,300)	$6,446	$8,420
CSPCo	(407)	(1,350)	2,762	3,671
I&M	1,115	(203)	4,315	5,750
KPCo	143	(142)	740	1,011
OPCo	(32)	(1,655)	5,260	7,052
PSO	699	(73)	2,112	2,471
SWEPCo	901	254	2,100	2,566
TCC	747	(31)	2,536	3,238
TNC	338	152	1,070	1,469

Nine Months ended September 30, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in thousands)			
APCo	$953	$(3,900)	$19,338	$25,261
CSPCo	(1,220)	(4,050)	8,287	11,013
I&M	3,345	(607)	12,945	17,249
KPCo	430	(424)	2,221	3,032
OPCo	(94)	(4,967)	15,779	21,156
PSO	2,096	(219)	6,336	7,413
SWEPCo	2,703	762	6,300	7,698
TCC	2,241	(93)	7,608	9,713
TNC	1,014	456	3,210	4,406

9. 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.

10. FINANCING ACTIVITIES

Long-term debt and other securities issued and retired during the first nine months of 2004 were:

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in thousands)	(%)	
Issuances:				
APCo	Senior Unsecured Notes	$125,000	Variable	2007
CSPCo	Installment Purchase Contracts	48,550	Variable	2038

CSPCo	Installment Purchase Contracts	43,695	Variable	2038
PSO	Installment Purchase Contracts	33,700	Variable	2014
PSO	Senior Unsecured Notes	50,000	4.70	2009
SWEPCo	Installment Purchase Contracts	53,500	Variable	2019
SWEPCo	Installment Purchase Contracts	41,135	Variable	2011

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in thousands)	(%)	
Retirements:				
APCo	First Mortgage Bonds	21,000	7.70	2004
APCo	First Mortgage Bonds	45,000	7.125	2024
APCo	Installment Purchase Contracts	40,000	5.45	2019
CSPCo	First Mortgage Bonds	11,000	7.60	2024
CSPCo	Installment Purchase Contracts	48,550	6.375	2020
CSPCo	Installment Purchase Contracts	43,695	6.25	2020
I&M	First Mortgage Bonds	30,000	7.20	2024
I&M	First Mortgage Bonds	25,000	7.50	2024
I&M	Senior Unsecured Notes	150,000	6.875	2004
OPCo	Installment Purchase Contracts	50,000	6.85	2022
OPCo	Notes Payable	3,000	6.27	2009
OPCo	Notes Payable	4,390	6.81	2008
OPCo	First Mortgage Bonds	10,000	7.30	2024
OPCo	Senior Unsecured Notes	140,000	7.375	2038
OPCo	Senior Unsecured Notes	100,000	6.75	2004
OPCo	Senior Unsecured Notes	75,000	7.00	2004
PSO	Notes Payable to Trust	77,320	8.00	2037
PSO	Installment Purchase Contracts	1,000	5.90	2007
PSO	Installment Purchase Contracts	33,700	4.875	2014
SWEPCo	Installment Purchase Contracts	53,500	7.60	2019
SWEPCo	Installment Purchase Contracts	12,290	6.90	2004
SWEPCo	Installment Purchase Contracts	12,170	6.00	2008
SWEPCo	Installment Purchase Contracts	17,125	8.20	2011
SWEPCo	First Mortgage Bonds	80,000	6.875	2025
SWEPCo	First Mortgage Bonds	40,000	7.75	2004
SWEPCo	Notes Payable	5,122	4.47	2011
SWEPCo	Notes Payable	2,250	Variable	2008
TCC	Notes Payable to Trust	140,889	8.00	2037
TCC	First Mortgage Bonds	6,195	6.625	2005
TCC	Securitization Bonds	48,551	3.54	2005
TNC	First Mortgage Bonds	24,036	6.125	2004

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in thousands)	(%)	
Defeasance:				
TCC	First Mortgage Bonds	$27,400 (a)	7.25	2004
TCC	First Mortgage Bonds	65,763 (a)	6.625	2005
TCC	First Mortgage Bonds	18,581 (a)	7.125	2008

(a) Trust fund assets for defeasance of First Mortgage Bonds of $100 million are included in Other Cash Deposits and $22 million in Bond Defeasance Funds in TCC's Consolidated Balance Sheets at September 30, 2004. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

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 thousands)	(%)	
Issuances:				
CSPCo	Notes Payable	$100,000	4.64	2010
KPCo	Notes Payable	20,000	5.25	2015
OPCo	Notes Payable	200,000	5.25	2015
OPCo	Notes Payable	200,000	3.32	2006
SWEPCo	Notes Payable	50,000	4.45	2010
Retirements:				
None.				

Lines of Credit - AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a utility money pool, which funds the utility subsidiaries and a non-utility money pool, which funds the majority of the non-utility subsidiaries. Utility money pool participants include AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC (domestic utility companies). In addition, the AEP System also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. The AEP System Corporate Borrowing Program operates in accordance with the terms and conditions outlined by the SEC. AEP has authority from the SEC through March 31, 2006 for short-term borrowings sufficient to fund the utility money pool and the non-utility money pool as well as its own requirements in an amount not to exceed $7.2 billion. The utility money pool participants' money pool activity and corresponding SEC authorized limits for the first nine months of 2004 are described in the following table:

Authorized Borrowing Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of September 30, 2004	SEC Short-Term Limit
		(in thousands)		
AEGCo	$56,525	$-	$(15,497)	$125,000
APCo	172,423	32,575	23,779	600,000
CSPCo	29,687	184,962	158,371	350,000
I&M	216,528	16,625	(98,762)	500,000
KPCo	44,749	38,242	37,779	200,000
OPCo	81,862	297,136	232,212	600,000
PSO	145,619	20,076	(19,259)	300,000
SWEPCo	71,252	96,615	96,615	350,000
TCC	109,696	427,414	172,051	600,000
TNC	16,136	85,482	54,495	250,000

For the first nine months of 2004, the maximum and minimum interest rates for funds borrowed from the utility money pool were 1.92% and 1.32%, respectively. For the first nine months of 2004, the maximum and minimum interest rates for funds loaned to the utility money pool were 1.93% and 0.89%, respectively.

REGISTRANT SUBSIDIARIES' COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is a combined presentation of certain components of the registrant subsidiaries' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, and (iii) footnotes of each individual registrant. The Registrants' Combined Management's Discussion and Analysis section of the 2003 Annual Report should be read in conjunction with this report.

Significant Matters

RTO Formation

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

Our AEP East companies joined PJM RTO on October 1, 2004. To minimize the credit requirements and operating constraints when joining PJM, the AEP East companies as well as Wheeling Power Company and Kingsport Power Company, have agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due the AEP East companies, and to save PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

AEP West companies are members of ERCOT or SPP. In February 2004, the FERC granted RTO status to the SPP, subject to fulfilling specified requirements. In October 2004, the FERC issued an order granting final RTO status to SPP subject to certain filings. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

FERC Order on Regional Through and Out Rates

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

AEP and several other utilities in the Combined Footprint have filed a proposal for new rates to become effective December 1, 2004. The AEP East companies received approximately $157 million of T&O rate revenues for the twelve months ended December 31, 2003. At this time, management is unable to predict whether the rate design approved by the FERC will fully compensate the AEP East companies for their lost T&O revenues and whether any resultant increase in rates applicable to AEP's internal load will be recoverable on a timely basis from state retail customers. Unless new replacement rates compensate AEP for its lost revenues and any increase in AEP East Companies' transmission expenses from these new rates are fully recovered in retail rates on a timely basis, future results of operations, cash flows and financial condition will be adversely affected.

Texas Regulatory Activity

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

The Texas Legislation, among other things:
o provides for the recovery of generation-related regulatory assets and other stranded generation costs through securitization and non- bypassable wires charges,
o requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility,
o provides for an earnings test for each of the years 1999 through 2001 and,
o provides for a stranded cost True-up Proceeding after January 10, 2004.

The True-up Proceedings will determine the amount and recovery of:
o stranded generation plant costs and generation-related regulatory assets including any unrefunded accumulated excess earnings (net stranded generation costs),
o carrying charges on true-up-amounts from January 1, 2002 (the commencement date of retail competition),
o a true-up of actual market prices determined through legislatively- mandated capacity auctions to the power costs used in the PUCT's excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up),

o final approved deferred fuel balance,
o excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
o and other true-up items.

TCC's recorded net regulatory asset for amounts subject to approval in the True-up Proceeding is approximately $1.5 billion at September 30, 2004 of which $1.3 billion represents net stranded generation costs.

In September 2004, the PUCT held true-up hearings for another utility, CenterPoint Energy, Inc. (CenterPoint). In that case the PUCT is expected to issue an order later in November 2004 addressing numerous items and that decision may provide indications of possible PUCT actions in TCC's true-up proceedings including:
o the methodology for calculating the recoverable carrying cost related to the True-up Proceedings,
o whether to and how to modify the calculation of the wholesale capacity auction true-up, and
o whether the amount of depreciation in the ECOM model on generation assets for 2002 and 2003 used to calculate the wholesale capacity auction true-up is a recovery of net stranded generation costs and should reduce the recoverable cost. The total TCC depreciation in the ECOM model for the 2002-2003 period was $238 million.

When TCC's True-up Proceeding is completed, TCC currently intends to file to recover PUCT-approved net stranded generation costs and other recoverable true-up amounts that are in excess of current securitized amounts, plus appropriate carrying charges, through a non-bypassable competition transition charge in the regulated T&D rates. TCC may seek to securitize the approved net stranded generation costs plus related carrying costs. The annual costs of securitization are recoverable through a non-bypassable transition charge collected by the T&D utility over the term of the securitization bonds.

TCC will seek to recover in the True-up Proceeding an amount in excess of the $1.5 billion recorded net true-up regulatory asset through September 30, 2004. This is primarily due to TCC not having accrued a carrying cost on its net regulatory asset due to litigation and uncertainties associated with the treatment and measurement of such amounts by the PUCT. Management expects that its review of the final order in the CenterPoint case will resolve numerous uncertainties about applicable PUCT positions and that TCC will be able to record a carrying cost in the fourth quarter of 2004.

Due to the preliminary nature of the pending CenterPoint proceedings and the consequent uncertainty, differences between CenterPoint's and TCC's facts and circumstances and the lack of direct applicability of the CenterPoint proceeding to TCC's recorded assets, management cannot, at this time, determine whether disallowances that may be applicable to CenterPoint would be applicable to TCC. Management believes that TCC's recorded regulatory assets are in compliance with Texas Legislation and TCC intends to seek vigorously recovery of these amounts. If, however, management determines that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.5 billion, and management is able to estimate the amount of such non-recovery, TCC will record a provision for such amount which could have a material adverse effect on future results of operations, cash flows and possible financial condition. To the extent decisions in the TCC True-up Proceeding differ from management expectations based in part on their evaluation of the final CenterPoint decision, additional material disallowances are possible.

In another matter before to PUCT, TCC has filed for an adjusted $41 million base rate increase in its retail distribution rates. After hearing the case the ALJ has recommended a reduction in existing rates of $33 million to $43 million depending on the final treatment of consolidated tax savings and other remanded issues. TCC defended vigorously the requested increase and challenged the ALJ's recommendation in a brief. Hearings were held on the consolidated tax savings remand issue in September 2004. The PUCT is expected to issue a decision in the fourth quarter of 2004.

See Notes 3 and 4 for further discussion of Texas Regulatory Activity.

Ohio Regulatory Activity

The Ohio Electric Restructuring Act of 1999 (Ohio Act) provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. After the end of the MDP, January 1, 2006, customers were scheduled to move to market prices for the supply of electricity.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed rate stabilization plans with the PUCO addressing prices following the end of the MDP. If approved by the PUCO, prices would be established pursuant to CSPCo's and OPCo's plans for the period from January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental, RTO costs and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. The plans include annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo) in 2006, 2007 and 2008 and the opportunity for additional generation-related increases upon PUCO review and approval. CSPCo's and OPCo's Rate Stabilization Plans also provide for the deferral of environmental construction and in-service carrying costs plus PJM RTO administrative fees in 2004 and

2005 for recovery through wires charges in 2006 through 2008. A non-affiliated utility received an order which rejected its request for automatic increases and cost deferrals during the MDP period. The PUCO has indicated in FirstEnergy companies' rate stabilization plans that these plans are specific to a company's requirements and characteristics and the PUCO's order in one case should not be considered a precedent for the plan of another company's rate stabilization plan. Management cannot predict whether CSPCo's and OPCo's plans will be approved as submitted nor can management predict the ultimate impact these proceedings will have on revenues, results of operations and cash flows. See Note 4 for further discussion of Ohio Regulatory Activity.

Unit Power Agreements

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) such amounts, when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement expires on December 31, 2004. The agreement will be extended through December 7, 2022, subject to both KPSC and FERC approval.

Litigation

AEP subsidiaries continue to be involved in various litigation matters as described in the "Significant Factors - Litigation" section of Registrants' Combined Management's Discussion and Analysis in the 2003 Annual Report. The 2003 Annual Report should be read in conjunction with this report in order to understand other litigation matters that did not have significant changes in status since the issuance of the 2003 Annual Report, but may have a material impact on future results of operations, cash flows and financial condition. Other matters described in the 2003 Annual Report that did not have significant changes during the first nine months of 2004, that should be read in order to gain a full understanding of the current litigation include disclosure related to Potential Uninsured Losses.

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation under "Environmental Matters".

Enron Bankruptcy

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

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

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

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

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In August 2004, the SEC announced it would conduct hearings on this issue. The hearing is scheduled for January 2005.

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUHCA's single region requirement. In its ruling, the appeals court said that the SEC failed to support and explain its conclusions that the interconnection and single region requirements are satisfied.

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

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas Retail Electric Provider (REP), filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against AEP and four of its 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 TCC and TNC, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. AEP and its subsidiaries filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. AEP and its subsidiaries filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against AEP and its subsidiaries. TCE has appealed the trial court's decision to the United States Court of Appeals for the Fifth Circuit.

Energy Market Investigations

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

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. AEP responded to the complaint in September 2004. In 2003, AEP recorded a provision related to these matters. AEP has engaged in settlement discussions with several agencies and is evaluating whether to conclude settlements in order to put these investigations behind AEP even though management believes the Company has meritorious legal positions and defenses. If AEP elects to settle all matters, the payments could exceed the 2003 provision and could have a material impact on our 2004 earnings and cash flows.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the Clean Air Act for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. No action can be commenced until 60 days after the date of notice.

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

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On August 30, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the reporting of volatile organic compound emissions at the Pirkey Plant.

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

Carbon Dioxide Public Nuisance Claims

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

Environmental Matters

As discussed in the 2003 Annual Report, there are emerging environmental control requirements that management expects will result in substantial capital investments and operational costs. The sources of these future requirements include:

o Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO2), nitrogen oxide (NOx) and mercury emissions from coal-fired power plants,
o New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
o Possible future requirements to reduce carbon dioxide emissions to address concerns about global climatic change.

This discussion updates certain events occurring in 2004. You should also read the "Significant Factors - Environmental Matters" section within Registrants' Combined Management's Discussion and Analysis in the 2003 Annual Report for a description of all material environmental matters affecting us, including, but not limited to, (1) the current air quality regulatory framework, (2) estimated air quality environmental investments, (3) Superfund and state remediation, (4) global climate change, and (5) costs for spent nuclear fuel disposal and decommissioning.

Future Reduction Requirements for SO2, NOx, and Mercury

In 1997, the Federal EPA adopted new, more stringent national ambient air quality standards for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter non-attainment areas. The Federal EPA finalized designations for ozone non-attainment areas on April 15, 2004. On the same day, the Administrator of the Federal EPA signed a final rule establishing the elements that must be included in state implementation plans (SIPs) to achieve the new standards, and setting deadlines ranging from 2008 to 2015 for achieving compliance with the final standard, based on the severity of non-attainment. All or parts of 474 counties are affected by this new rule, including many urban areas in the Eastern United States.

The Federal EPA identified SO2 and NOx emissions as precursors to the formation of fine particulate matter. NOx emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NOx and SO2 from the AEP System's generating units are highly probable. In addition, the Federal EPA proposed a set of options for future mercury controls at coal-fired power plants.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% each in emissions of SO2, NOx and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

o The Federal EPA proposed a Clean Air Interstate Rule (CAIR) to reduce SO2 and NOx emissions across the eastern half of the United States (29 states and the District of Columbia) and make progress toward attainment of the new fine particulate matter and ground-level ozone national ambient air quality standards. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.

o The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The CAIR would require affected states to include, in their SIPs, a program to reduce NOx and SO2 emissions from coal-fired electric utility units. SO2 and NOx emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO2 emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NOx emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO2 and NOx trading programs were proposed on June 10, 2004.

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

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of maximum achievable control technology (MACT) on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain units have achieved comparable levels of mercury reduction by installing conventional SO2 (scrubbers) and NOx (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite. The proposed standards for sub-bituminous coals potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and AEP supports, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO2 and NOx reduction requirements imposed on the same sources under the CAIR. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, which can be used to comply with the more stringent SO2 and NOx requirements, have also proven effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 tons to 34 tons by 2010 and to 15 tons by 2018. A supplemental proposal including unit-specific allocations and a framework for the emissions budgeting and trading program preferred by the Federal EPA was published in the Federal Register on March 16, 2004. AEP filed comments on both the initial proposal and the supplemental notice in June 2004.

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

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that AEP subsidiaries will invest in additional conventional pollution control technology on a major portion of their coal-fired power plants. Finalization of new requirements for further SO2, NOx and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control. The cost of such facilities could have an adverse effect on future results of operations, cash flows and financial condition unless recovered from customers.

New Source Review Litigation

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

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

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

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

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

Clean Water Act Regulation

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

	Estimated Compliance Investments
	(in millions)
APCo	$21
CSPCo	19
I&M	118
OPCo	31

Other Matters

As discussed in the 2003 Annual Report, there are several "Other Matters" affecting AEP subsidiaries. The current status of FERC's market power mitigation efforts is described below.

FERC Market Power Mitigation

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. These two screening tests include a "pivotal supplier" test which determines if the market load can be fully served by alternative suppliers and a "market share" test which compares the amount of surplus generation at the time of the applicant's minimum load. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order and directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way.

On August 9, 2004, AEP submitted its Market Power Analysis pursuant to the FERC's Orders on Rehearing. The analysis focused on the three major areas in which AEP serves load and owns generation resources -- ECAR, SPP and ERCOT, and the "first tier" control areas for each of those areas.

The pivotal supplier and market share screen analyses that AEP filed demonstrated that AEP does not possess market power in any of the control areas to which it is directly connected (first-tier markets). AEP passed both screening tests in all of its "first tier" markets. In its three "home" control areas, AEP easily passed the pivotal supplier test. AEP, as part of PJM, also passes the market share screen for the PJM destination market. AEP also passed the market share screen for ERCOT. AEP did not pass the market share screen as designed by the FERC for the SPP control area. Consequently, AEP also submitted substantial additional information, including historical purchase and sales data that demonstrates that AEP does not possess market power in any of the "home" destination markets. AEP requested that its existing market-based pricing authorization in all markets be continued based on this analysis. AEP also requested that the FERC rule without instituting a proceeding and without setting a refund date. This case is pending.

CONTROLS AND PROCEDURES

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

As of September 30, 2004, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as events warrant.

There have been no changes in the Registrants' internal controls over financial reporting (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) during the third quarter of 2004 that have materially affected, or are reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see Note 5, Commitments and Contingencies, incorporated herein by reference.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended September 30, 2004 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
07/01/04 - 07/31/04	175	$65	-	$-
08/01/04 - 08/31/04	-	-	-	-
09/01/04 - 09/30/04	-	-	-	-
Total	175	$65	-	$-

(1) I&M repurchased an aggregate of 175 shares of its 4.12% cumulative preferred stock, in a privately-negotiated transaction outside of an announced program.

Item 5. Other Information

NONE

Item 6. Exhibits

AEP

*10(a) - Supplemental Retirement Savings Plan [Current Report on Form 8-K, dated September 1, 2004, File No. 1-3525, Exhibit 99.1]
10(b) - Letter Agreement dated June 9, 2004 between AEPSC and Carl English.
10(c) - Form of Performance Share Award Agreement

TCC

10(a) - Purchase and Sale Agreement by and between AEP Texas Central Company and City of San Antonio (acting by and through the City Public Service Board of San Antonio) and Texas Genco, L.P., dated as of September 3, 2004.

OPCo

10(a) - Amendment No. 9, dated as of July 1, 2003 to Station Agreement dated as of January 1, 1968, as amended, among OPCo, Buckeye Power, Inc. and Cardinal Operating Company

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.

*Denotes exhibits incorporated by reference.

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 5, 2004

KENTUCKY POWER COMPANY
Computation of Ratios of Earnings to Fixed Charges
(in thousands except ratio data)

	Year Ended December 31,					Twelve Months Ended
	1999	2000	2001	2002	2003	9/30/04
Fixed Charges:						
Interest on First Mortgage Bonds	$12,712	$9,503	$6,178	$2,206	$-	$-
Interest on Other Long-term Debt	13,525	16,367	18,300	23,429	26,467	27,017
Interest on Short-term Debt	2,552	3,295	2,329	1,751	1,104	794
Miscellaneous Interest Charges	869	2,523	1,059	1,084	1,772	1,977
Estimated Interest Element in Lease Rentals	1,200	1,700	1,200	1,000	600	600
Total Fixed Charges	$30,858	$33,388	$29,066	$29,470	$29,943	$30,388
Earnings:						
Net Income Before Cumulative Effect of Accounting Change	$25,430	$20,763	$21,565	$20,567	$33,464	$33,686
Plus Federal Income Taxes	12,993	17,884	9,553	9,235	9,764	6,869
Plus State Income Taxes	2,784	2,457	489	1,627	(89)	(841)
Plus Fixed Charges (as above)	30,858	33,388	29,066	29,470	29,943	30,388
Total Earnings	$72,065	$74,492	$60,673	$60,899	$73,082	$70,102
Ratio of Earnings to Fixed Charges	2.33	2.23	2.08	2.06	2.44	2.30

EXHIBIT 31.1
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Michael G. Morris, certify that:
1. I have reviewed this 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 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 report;

4. The registrant's other certifying officer(s) 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 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 report is being prepared;

evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

disclosed in this 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 officer(s) 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 5, 2004

By: /s/ Michael G. Morris

Michael G. Morris
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 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 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 report;

4. The registrant's other certifying officer(s) 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 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 report is being prepared;

b. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c. disclosed in this 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 officer(s) 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: November5, 2004

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 endedSeptember 30, 2004as filed with the Securities and Exchange Commission on the date hereof (the "Reports"), I, Michael G. Morris, 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/Michael G. Morris

Michael G. Morris
November 5, 2004

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 endedSeptember 30, 2004as 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 5, 2004

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