Appendix A to the
Proxy Statement

American Electric Power

2006 Annual Report

**Audited Consolidated Financial Statements and
Management's Financial Discussion and Analysis**

AMERICAN®
ELECTRIC
POWER

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AEP COMMON STOCK AND DIVIDEND INFORMATION

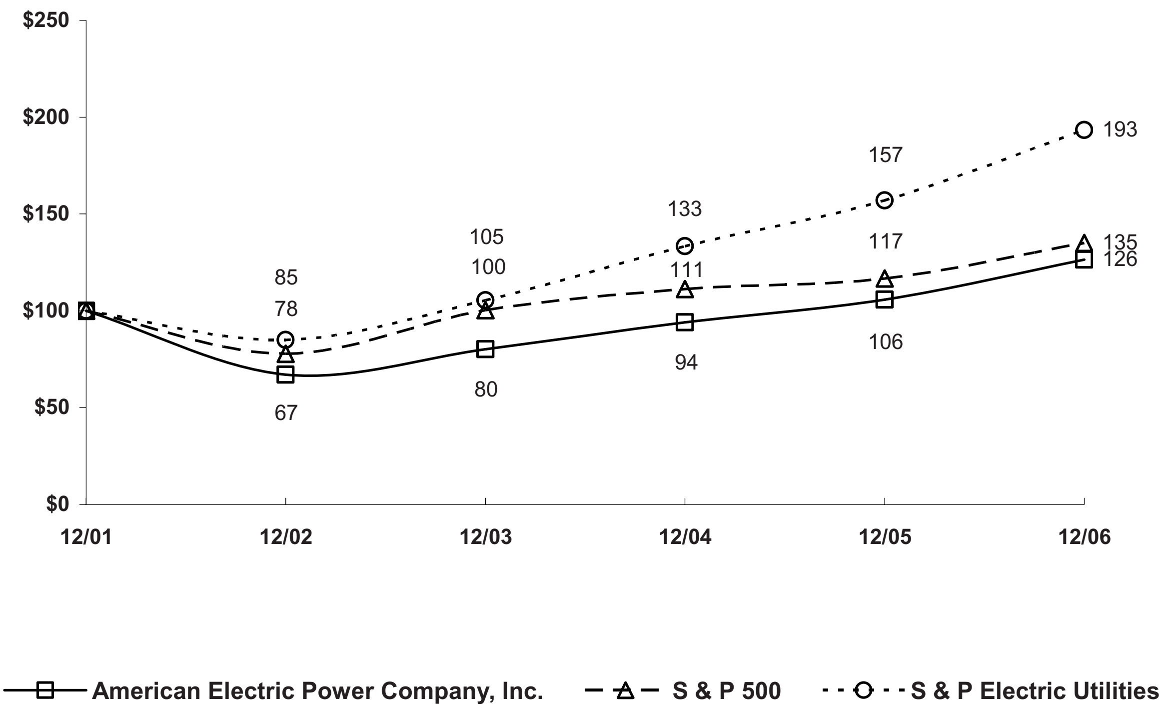
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2006	$ 43.13	$ 36.49	$ 42.58	$ 0.39
September 30, 2006	37.30	34.10	36.37	0.37
June 30, 2006	35.19	32.27	34.25	0.37
March 31, 2006	38.48	33.96	34.02	0.37
December 31, 2005	40.80	35.57	37.09	0.37
September 30, 2005	39.84	36.34	39.70	0.35
June 30, 2005	37.00	33.79	36.87	0.35
March 31, 2005	36.34	32.25	34.06	0.35

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2006, AEP had approximately 112,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among American Electric Power Company, Inc., The S & P 500 Index
And The S & P Electric Utilities Index



* $100 invested on 12/31/01 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

www.researchdatagroup.com/S&P.htm

GLOSSARY OF TERMS

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

Term	Meaning
ADFIT	Accumulated Deferred Federal Income Taxes.
ADITC	Accumulated Deferred Investment Tax Credits.
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility 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 off-system sales of the member companies.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
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.
EDFIT	Excess Deferred Federal Income Taxes.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities."
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations."
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipeline Company, a former AEP subsidiary.

Term	Meaning
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
IKEC	Indiana-Kentucky Electric Corporation, a subsidiary of OVEC.
IPP	Independent Power Producer.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, a former AEP subsidiary.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
NYMEX	New York Mercantile Exchange.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTB	Price-to-Beat.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
PURPA	Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading 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.
RSP	Rate Stabilization Plan.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.

Term	Meaning
SCR	Selective Catalytic Reduction.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, “Accounting for the Effects of Certain Types of Regulation.”
SFAS 109	Statement of Financial Accounting Standards No. 109, “Accounting for Income Taxes.”
SFAS 133	Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities.”
SFAS 143	Statement of Financial Accounting Standards No. 143, “Accounting for Asset Retirement Obligations.”
SFAS 158	Statement of Financial Accounting Standards No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans.”
SFAS 159	Statement of Financial Accounting Standards No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities.”
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant.
Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TC	Transition Charge.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Utility Money Pool	AEP System’s Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters).
- Our ability to constrain operation and maintenance costs.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate trends.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas and other energy-related commodities.
- Changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia and membership in and integration into regional transmission organizations.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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

	2006	2005	2004	2003	2002
			(in millions)		
STATEMENTS OF OPERATIONS DATA					
Total Revenues	$ 12,622	$ 12,111	$ 14,245	$ 14,833	$ 13,641
Operating Income	$ 1,966	$ 1,927	$ 1,983	$ 1,743	$ 1,930
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 992	$ 1,029	$ 1,127	$ 522	$ 485
Discontinued Operations, Net of Tax	10	27	83	(605)	(654)
Extraordinary Loss, Net of Tax	-	(225)	(121)	-	-
Cumulative Effect of Accounting Changes, Net of Tax	-	(17)	-	193	(350)
Net Income (Loss)	$ 1,002	$ 814	$ 1,089	$ 110	$ (519)
BALANCE SHEETS DATA			(in millions)		
Property, Plant and Equipment	$ 42,021	$ 39,121	$ 37,294	$ 36,031	$ 34,132
Accumulated Depreciation and Amortization	15,240	14,837	14,493	14,014	13,544
Net Property, Plant and Equipment	$ 26,781	$ 24,284	$ 22,801	$ 22,017	$ 20,588
Total Assets	$ 37,987	$ 36,172	$ 34,636	$ 36,736	$ 36,003
Common Shareholders' Equity	$ 9,412	$ 9,088	$ 8,515	$ 7,874	$ 7,064
Cumulative Preferred Stocks of Subsidiaries	$ 61	$ 61	$ 127	$ 137	$ 145
Trust Preferred Securities (a)	$ -	$ -	$ -	$ -	$ 321
Long-term Debt (b)	$ 13,698	$ 12,226	$ 12,287	$ 14,101	$ 10,190
Obligations Under Capital Leases (b)	$ 291	$ 251	$ 243	$ 182	$ 228
COMMON STOCK DATA					
Basic Earnings (Loss) per Common Share:					
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 2.52	$ 2.64	$ 2.85	$ 1.35	$ 1.46
Discontinued Operations, Net of Tax	0.02	0.07	0.21	(1.57)	(1.97)
Extraordinary Loss, Net of Tax	-	(0.58)	(0.31)	-	-
Cumulative Effect of Accounting Changes, Net of Tax	-	(0.04)	-	0.51	(1.06)
Basic Earnings (Loss) Per Share	$ 2.54	$ 2.09	$ 2.75	$ 0.29	$ (1.57)
Weighted Average Number of Basic Shares Outstanding (in millions)	394	390	396	385	332
Market Price Range:					
High	$ 43.13	$ 40.80	$ 35.53	$ 31.51	$ 48.80
Low	$ 32.27	$ 32.25	$ 28.50	$ 19.01	$ 15.10
Year-end Market Price	$ 42.58	$ 37.09	$ 34.34	$ 30.51	$ 27.33
Cash Dividends Paid per Common Share	$ 1.50	$ 1.42	$ 1.40	$ 1.65	$ 2.40
Dividend Payout Ratio	59.1%	67.9%	50.9%	569.0%	(152.9)%
Book Value per Share	$ 23.73	$ 23.08	$ 21.51	$ 19.93	$ 20.85

(a) See "Trust Preferred Securities" section of Note 15.

(b) Including portion due within one year.

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

We operate an extensive portfolio of assets including:

- Almost 36,000 megawatts of generating capacity as of December 31, 2006, one of the largest complements of generation in the U.S., the majority of which provides a significant cost advantage in many of our market areas.
- Approximately 39,000 miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 207,632 miles of distribution lines that deliver electricity to customers.
- Substantial coal transportation assets (more than 8,300 railcars, 2,600 barges, 51 towboats and one active coal handling terminal with 20 million tons of annual capacity).

EXECUTIVE OVERVIEW

BUSINESS STRATEGY

Our mission is to bring comfort to our customers, support business and commerce and build strong communities. We invest in our core utility business operations to execute our mission. Our objective is to be an economical, reliable and safe provider of electric energy to the markets that we serve. We plan to buy or build additional generation to meet franchise service obligations. Our plan entails designing, building, improving and operating reasonably priced, environmentally-compliant, efficient sources of power and maximizing the amount of power delivered from these facilities. We intend to maintain and enhance our position as a safe and reliable provider of electric energy by making significant investments in environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers while providing a fair return for our shareholders through a stable stream of cash flows, enabling us to pay dependable, competitive dividends. We operate our generating assets to maximize our productivity and profitability after meeting our native load requirements.

In summary, our business strategy is to:

- Respect our employees and give them the opportunity to be as successful as they can be.
- Meet the energy needs of our customers in ways that improve their quality of life and protect the environment today and for generations to come.
- Improve the environmental and safety performance of our generating fleet, and grow that fleet.
- Set the standards for safety, efficiency and reliability in our electric transmission and distribution systems.
- Nurture strong and productive relationships with public officials and regulators.
- Provide leadership, integrity and compassion as a corporate citizen to every community we serve.

OUTLOOK FOR 2007

We remain focused on the fundamental earning power of our utilities and committed to maintaining our credit quality. To achieve our goals we plan to:

- Obtain permits and continue to pursue federal tax credits for our proposed IGCC plants in Ohio and West Virginia and move forward with the engineering and design of these plants.
- Begin construction of over 2,000 MW of new generation in Arkansas, Louisiana and Oklahoma with commercial operation dates ranging from 2007 through 2012.
- Purchase 1,576 MW of additional gas-fired generating unit capacity.
- Invest in transmission projects such as the AEP Interstate Project, the Electric Transmission Texas Project, a joint venture with MidAmerican Energy Holdings Company (MidAmerican), and others to ensure competitive energy prices for electric consumers in and around congested areas.
- Maintain our strong financial condition and credit ratings.
- Control our operating and maintenance costs.
- Obtain favorable resolutions to our numerous rate proceedings.
- Continue developing strong regulatory relationships through operating company interaction with the various regulatory bodies.

There are, nevertheless, certain risks and challenges including:

- Regulatory activity in Virginia, Texas, Oklahoma, Ohio and with the FERC.
- Legislative activity in Ohio and Virginia regarding future regulatory operating environment.
- Fuel cost volatility and fuel cost recovery, including related transportation issues.
- Wholesale market volatility.
- Plant availability.
- Weather.

Regulatory Activity

In 2007, our significant regulatory activities will include:

- Pursuit of favorable resolutions of our pending base rate cases in Virginia, Texas and Oklahoma.
- Influence of key legislative outcomes regarding Ohio and Virginia's future regulatory operating environment.
- Legal proceedings regarding appeals related to Texas stranded cost recoveries.
- Continued regulatory proceedings before the FERC seeking:
  - proper regional transmission rates in our eastern transmission zone,
  - approval of SECA rates collected subject to refund through March 31, 2006 and
  - approval and incentives to construct a 550-mile 765 kV transmission line project in the PJM footprint.
- Our request before the PUCT regarding new transmission rates and designation as a utility for Electric Transmission Texas LLC, our joint venture with MidAmerican.

Fuel Costs

During 2006, spot market prices for coal and natural gas declined. In contrast, market prices for fuel oil increased and continue to be volatile. We still experienced an eight percent increase in coal costs during 2006 and expect a seven to nine percent increase in 2007 even considering softening fuel markets and favorable transportation effects during the year. The increase is primarily due to expiring lower priced contracts being replaced with new higher priced contracts. We have price risk related to these commodity prices. We do not have an active fuel cost recovery adjustment mechanism in Ohio, which represents approximately 20% of our fuel costs. In Indiana, our fuel recovery mechanism is temporarily capped, subject to preestablished escalators, at a fixed rate through June 2007. As a consequence of the cap, we incurred under-recoveries of $26 million for 2006 and expect additional under-recoveries through June 2007.

Our Ohio companies increased their generation rates in 2006, as previously approved by the PUCO in our Rate Stabilization Plans. These increased rates, along with the reinstated fuel cost adjustment rate clause for over- or under-recovery of fuel, off-system sales margins, certain transmission items and related costs effective July 1, 2006 in West Virginia, will help offset future negative impacts of fuel price increases on our gross margins.

Capital Expenditures

Our current projections call for capital expenditures of approximately $9.9 billion from 2007-2009. For 2007, we forecast approximately $3.5 billion in construction expenditures, excluding allowances for funds used during construction. We also forecast purchases of additional gas-fired generating units for a total of $427 million. Our current projections are as follows:

		(in millions)
Generation	$	996
Distribution		848
Environmental		935
Transmission		496
Corporate		165
Total Construction Expenditures		3,440
Purchases of Gas-Fired Units		427
Total Capital Expenditures	$	3,867

Off-System Sales

In 2007, we expect a decline in off-system sales revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power. This decline is primarily due to expected increases in sales to municipal and energy cooperative customers and demand for electricity from our native load retail customers including Ormet, which reduces the amount of power available for off-system sales. In addition, lower expected generating plant availability due to environmental retrofit outages likely will result in lower off-system sales.

Corporate Sustainability Reporting

Our first Corporate Responsibility report will be published and available in 2007. In 2004 a subcommittee of the Policy Committee of our Board of Directors prepared a report entitled, “An Assessment of AEP’s Actions to Mitigate the Economic Impacts of Emissions Policies.” While the 2004 report was quite well received, it primarily addressed environmental issues we face. The scope of our 2007 report will reach beyond environmental issues and address other matters that create risk to our sustainability into the future. The report will be developed using the sustainability reporting guidelines issued by the Global Reporting Initiative and will address issues such as leadership, strategy and management, workforce issues including safety and health, climate change and energy security, reliability and growth.

2006 RESULTS

We had a year of continued improvement and many accomplishments in 2006. Our total shareholder return was 18.8% and we increased our quarterly dividend 5.4% to $0.39 per share.

We continued receiving favorable outcomes in various regulatory activities resulting in increased revenues. We continued securing new power supply contracts with municipal and cooperative customers and our barging subsidiary produced strong results. Some of these positive factors were offset in part by mild weather and an impairment loss from the sale of the Plaquemine Cogeneration Facility to Dow Chemical Company.

We announced plans for new generation in Oklahoma, Louisiana and Arkansas; continued work on engineering and design on new clean-coal plants in Ohio and West Virginia; announced a proposal to build a 550-mile, 765-kilovolt transmission line from West Virginia to New Jersey to address west-east power flow and congestion issues in PJM; announced a joint venture with MidAmerican to build much needed transmission capacity in Texas and we agreed to purchase additional gas-fired generating plants in 2007 to address capacity concerns in the east.

Our regulatory accomplishments include the implementation of new base rates in Ohio, Kentucky, West Virginia and Virginia (subject to refund) and we have taken a step forward in resolving the rate design issues related to our FERC transmission rates. Although various legal issues remain to be decided, we received a final order in our Texas True-up Proceeding and in October 2006 we received proceeds of $1.7 billion related to the securitization of our Texas regulatory assets. We received approval for our request to increase rates for recovery of incremental environmental and reliability costs in Virginia.

RESULTS OF OPERATIONS

Segments

Our primary business strategy and the core of our business focus on our electric utility operations. Within our Utility Operations segment, we centrally dispatch all generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Generation/supply in Ohio and Virginia continue to have commission-determined transition rates. Virginia is currently considering returning to regulation for generation. While our Utility Operations segment remains our primary business segment, the emergence of other areas of our business prompted us to identify two new business segments in 2006. One of these new segments is our MEMCO Operations segment, which reflects our significant ongoing barging activities. We also identified our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities in the ERCOT market area. We no longer consider Investments – Gas Operations and Investments – UK Operations as reportable segments because we have sold substantially all of those assets.

Starting in the fourth quarter of 2006, our new segments and their related business activities are as follows:

Utility Operations
- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

MEMCO Operations
- Bulk commodity barging operations.

Generation and Marketing
- IPPs, wind farms and marketing and risk management activities in ERCOT.

The table below presents our consolidated Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change for the years ended December 31, 2006, 2005 and 2004 (Earnings and Weighted Average Number of Basic Shares Outstanding in millions). We reclassified prior year amounts to conform to the current year's presentation.

	2006		2005		2004	
	Earnings	**EPS (b)**	**Earnings**	**EPS (b)**	**Earnings**	**EPS (b)**
Utility Operations	$ 1,028	$ 2.61	$ 1,018	$ 2.61	$ 1,175	$ 2.97
MEMCO Operations	80	0.20	21	0.05	12	0.03
Generation and Marketing	12	0.03	16	0.04	73	0.18
All Other (a)	(128)	(0.32)	(26)	(0.06)	(133)	(0.33)
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 992	$ 2.52	$ 1,029	$ 2.64	$ 1,127	$ 2.85
Weighted Average Number of Basic Shares Outstanding		394		390		396

(a) All Other includes:
- Parent company's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Our UK operations, which were sold in 2004.
- Our gas pipeline and storage operations, which were sold in 2004 and 2005.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility.

(b) The earnings per share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct equity interest in AEP's assets and liabilities as a whole.

2006 Compared to 2005

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change in 2006 decreased $37 million compared to 2005 primarily due to a $136 million after-tax impairment recorded in the third quarter of 2006 related to the sale of the Plaquemine Cogeneration Facility offset by a $59 million increase in MEMCO Operations earnings. Utility Operations earnings increased $10 million due to new retail rates implemented in Ohio, Kentucky, Oklahoma, Virginia and West Virginia mostly offset by unfavorable weather, decreases in transmission revenues from the loss of SECA rates and increases in regulatory amortization and operating expenses.

Average basic shares outstanding increased to 394 million in 2006 from 390 million in 2005 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 397 million as of December 31, 2006.

2005 Compared to 2004

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change in 2005 decreased $98 million compared to 2004 primarily due to gains on sales of equity investments in 2004 and a decrease in recorded stranded generation carrying costs income in 2005, as a result of the PUCT decisions related to TCC's True-up Proceeding.

Average basic shares outstanding decreased to 390 million in 2005 from 396 million in 2004 primarily due to the common stock share repurchase program executed in 2005. Actual shares outstanding were 394 million as of December 31, 2005.

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

Utility Operations

Our Utility Operations include primarily regulated revenues with direct and variable offsetting expenses and net reported commodity trading operations. We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross margin represents utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power.

	2006	**2005**	**2004**
		(in millions)	
Revenues	$ 12,011	$ 11,389	$ 10,764
Fuel and Purchased Power	4,669	4,288	3,704
Gross Margin	7,342	7,101	7,060
Depreciation and Amortization	1,435	1,315	1,281
Other Operating Expenses	3,843	3,801	3,749
Operating Income	2,064	1,985	2,030
Other Income, Net	177	103	330
Interest Charges and Preferred Stock Dividend Requirements	670	595	627
Income Tax Expense	543	475	558
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 1,028	$ 1,018	$ 1,175

Summary of Selected Sales and Weather Data
For Utility Operations
For the Years Ended December 31, 2006, 2005 and 2004

	2006	2005	2004
Energy Summary		**(in millions of KWH)**	
Retail:			
Residential	47,222	48,720	45,770
Commercial	38,579	38,605	37,203
Industrial	53,914	53,217	51,484
Miscellaneous	2,653	2,745	3,252
Total Retail (a)	142,368	143,287	137,709
Wholesale	44,564	47,785	57,409
Texas Wires Delivery	26,382	26,525	25,581
Total KWHs	213,314	217,597	220,699

(a) Does not include retail sales to Texas Commercial and Industrial (Texas C&I) customers, which are included in the Generation and Marketing segment. Sales by Texas C&I were formerly included in the Utility Operations segment. Total KWHs sold to Texas C&I customers were 296 million, 470 million and 911 million for 2006, 2005 and 2004, respectively.

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on results of operations. In general, degree day changes in our eastern region have a larger effect on results of operations than changes in our western region due to the relative size of the two regions and the associated number of customers within each. Cooling degree days and heating degree days in our service territory for the years ended December 31, 2006, 2005 and 2004 were as follows:

	2006	2005	2004
Weather Summary		**(in degree days)**	
Eastern Region			
Actual – Heating (a)	2,477	3,130	2,992
Normal – Heating (b)	3,078	3,088	3,086
Actual – Cooling (c)	923	1,153	877
Normal – Cooling (b)	985	969	974
Western Region (d)			
Actual – Heating (a)	1,172	1,377	1,382
Normal – Heating (b)	1,605	1,615	1,624
Actual – Cooling (c)	2,430	2,386	2,006
Normal – Cooling (b)	2,175	2,150	2,149

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region and Western Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region statistics represent PSO/SWEPCo customer base only.

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2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2005		$ 1,018
Changes in Gross Margin:		
Retail Margins	352	
Off-system Sales	(18)	
Transmission Revenues	(140)	
Other Revenues	47	
Total Change in Gross Margin		241
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(39)	
Asset Impairments and Other Related Charges	39	
Gain on Dispositions of Assets, Net	(50)	
Depreciation and Amortization	(120)	
Taxes Other Than Income Taxes	8	
Carrying Costs Income	59	
Other Income, Net	15	
Interest and Other Charges	(75)	
Total Change in Operating Expenses and Other		(163)
Income Tax Expense		(68)
Year Ended December 31, 2006		$ 1,028

Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change increased $10 million to $1,028 million in 2006. The key driver of the increase was a $241 million increase in Gross Margin offset by a $163 million increase in Operating Expenses and Other and a $68 million increase in Income Tax Expense.

The major components of the net increase in Gross Margin were as follows:

- Retail Margins increased $352 million primarily due to the following:
  - A $244 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSPs, a $67 million increase related to new rates implemented in other East jurisdictions of Kentucky, West Virginia and Virginia (subject to refund) and a $13 million increase related to new rates implemented in Oklahoma in June 2005.
  - A $123 million increase related to increased usage and customer growth of which $63 million relates to the purchase of the Ohio service territory of Monongahela Power in December 2005.
  - A $70 million increase related to increased sales to municipal, cooperative and other customers primarily as a result of new power supply contracts.
  - A $55 million increase related to decreased sharing of off-system sales margins with retail customers due to lower off-system sales and changes in the SIA.

  These increases were partially offset by:
  - A $148 million increase in delivered fuel cost, which relates to the AEP East companies with inactive, capped or frozen fuel clauses.
  - A $95 million decrease in usage related to mild weather. As compared to the prior year, our eastern region and western region experienced 21% and 15% declines, respectively, in heating degree days. Also compared to the prior year, our eastern region experienced a 20% decrease in cooling degree days.

- Margins from Off-system Sales decreased $18 million primarily due to lower generation availability in the west due to the sale of STP in May 2005, a reversal of a Texas regulatory provision in 2005 and lower margins from trading activities mostly offset by higher margins in the east.
- Transmission Revenues decreased $140 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $34 million recorded in 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. We have a pending proposal with the FERC to replace SECA revenues. See the "Transmission Rate Proceedings at the FERC" section of Note 4.
- Other Revenues increased $47 million primarily due to the sale of emission allowances and increased securitization revenues.

Utility Operating Expenses and Other and Income Taxes changed between years as follows:

- Other Operation and Maintenance expenses increased $39 million primarily due to increases in generation expenses related to base operations and maintenance, distribution expenses related to vegetation management and service reliability, expenses at the Plaquemine Cogeneration Facility and favorable insurance adjustments which reduced expenses in 2005. These increases were partially offset by favorable variances related to expenses from the January 2005 ice storm in Ohio and Indiana and the recovery of the ice storm expenses in Ohio in 2006 and a decrease in severance costs related to the 2005 staffing and budget review.
- Asset Impairments and Other Related Charges were $39 million in 2005 due to our retirement of two units at our Conesville Plant.
- Gain on Disposition of Assets, Net decreased $50 million primarily resulting from revenues related to the earnings sharing agreement with Centrica as stipulated in the purchase-and-sale agreement from the sale of our REPs in 2002. In 2005, we reached a settlement with Centrica and received $112 million related to two years of earnings sharing whereas in 2006 we received $70 million related to one year of earnings sharing.
- Depreciation and Amortization expense increased $120 million primarily due to increased Ohio regulatory asset amortization in conjunction with rate increases, increased Texas amortization of the securitized transition assets and higher depreciable property balances.
- Carrying Costs Income increased $59 million primarily due to negative adjustments in 2005 related to the Texas True-up Proceeding orders received from the PUCT and an increase related to the Virginia environmental and reliability deferred costs.
- Interest and Other Charges increased $75 million primarily due to additional debt issued in late 2005 and in 2006 and increasing interest rates, partially offset by an increase in allowance for borrowed funds used during construction.
- Income Tax Expense increased $68 million due to an increase in pretax income, state income taxes, changes in certain book/tax differences accounted for on a flow-through basis and the recording of tax reserve adjustments. See "AEP System Income Taxes" section below for further discussion of fluctuations related to income taxes.

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2004		$ 1,175
Changes in Gross Margin:		
Retail Margins	67	
Off-system Sales	17	
Transmission Revenues	(57)	
Other Revenues	14	
Total Change in Gross Margin		41
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(92)	
Asset Impairments and Other Related Charges	(39)	
Gain on Dispositions of Assets, Net	116	
Depreciation and Amortization	(34)	
Taxes Other Than Income Taxes	(37)	
Other Income, Net	(227)	
Interest and Other Charges	32	
Total Change in Operating Expenses and Other		(281)
Income Tax Expense		83
Year Ended December 31, 2005		$ 1,018

Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change decreased $157 million to $1,018 million in 2005. Key driver of the decrease included a $281 million increase in Operating Expenses and Other, offset in part by a $41 million increase in Gross Margin and an $83 million decrease in Income Tax Expense.

The major components of the net increase in Gross Margin were as follows:

- The increase in Retail Margins from our utility segment over the prior year was due to increased demand in both the East and the West as a consequence of higher usage in most classes and customer growth in the residential and commercial classes. The higher usage was primarily weather-related as cooling degree days increased 31% and 19% for the East and West, respectively. This load growth was partially offset by higher delivered fuel costs of approximately $129 million, of which the majority relates to our East companies with inactive fuel clauses.
- Margins from Off-system Sales for 2005 were $17 million higher than in 2004 due to favorable price margins partially offset by a decrease in gross margin principally due to the sale of almost all of our Texas generation assets to support Texas stranded cost recovery.
- Transmission Revenues decreased $57 million primarily due to the loss of through-and-out rates as mandated by the FERC.

Utility Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $92 million due to an $87 million increase in generation expense related to strong retail and wholesale sales and capacity requirements, increased plant maintenance in 2005 and PJM expenses of $30 million. Additionally, distribution maintenance expense increased $91 million from tree trimming and reliability work. These increases were partially offset by reduced administrative and general expenses of $90 million.
- Asset Impairments and Other Related Charges for 2005 included a $39 million impairment related to the retirement of two units at CSPCo's Conesville Plant.
- Gain on Dispositions of Assets, Net increased $116 million resulting from the receipt of net revenues related to the earnings sharing agreement with Centrica as stipulated in the purchase-and-sale agreement from the sale of our REPs in 2002. We reached an agreement with Centrica in March 2005 resolving disputes back to 2002 on how such amounts were calculated.
- Depreciation and Amortization expense increased $34 million primarily due to a higher depreciable asset base.
- Taxes Other Than Income Taxes increased $37 million due to increased property tax values and assessments and higher state excise taxes due to the increase in taxable KWH sales.
- Other Income, Net decreased $227 million primarily due to the following:
  - A $321 million decrease related to carrying costs recorded by TCC on its net stranded generation costs and its capacity auction true-up asset. In 2004, TCC booked $302 million of carrying costs income related to 2002 through 2004. Upon receipt of the final order in February 2006 in TCC's True-up Proceeding, we determined that adjustments to those carrying costs were required, resulting in carrying costs expense of $19 million in 2005 for TCC.

  This decrease was offset by:
  - A $56 million increase related to the establishment of regulatory assets for carrying costs on environmental capital expenditures and RTO expenses by our Ohio companies related to the Rate Stabilization Plans.
  - A $20 million increase related to increased interest income and increased AFUDC due to extensive construction activities occurring in 2005.
  - A $14 million increase related to the establishment of regulatory assets for carrying costs on environmental and reliability deferred costs for APCo.
- Interest and Other Charges decreased $32 million from the prior period primarily due to refinancings of higher coupon debt at lower interest rates and the retirement of debt in 2004 and 2005.
- Income Tax Expense decreased $83 million due to the decrease in pretax income and tax return adjustments. See "AEP System Income Taxes" section below for further discussion of fluctuations related to income taxes.

MEMCO Operations

2006 Compared to 2005

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our MEMCO Operations segment increased from $21 million in 2005 to $80 million in 2006. The increase was primarily related to strong demand and a tight supply of barges resulting in increased barge freight rates and utilization. Additionally, 2006 operating conditions for our barging operations improved from 2005 when hurricanes, severe ice and flooding caused increased operating costs.

2005 Compared to 2004

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our MEMCO Operations segment increased from $12 million in 2004 to $21 million in 2005. The increase was primarily related to favorable barging activity due to strong demand and a tight supply of barges, resulting in a 45% increase in freight rates between 2004 and 2005.

Generation and Marketing

2006 Compared to 2005

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our Generation and Marketing segment in 2006 was essentially flat when compared to 2005.

2005 Compared to 2004

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our Generation and Marketing segment decreased from $73 million in 2004 to $16 million in 2005. The decrease was primarily due to a $64 million after-tax gain on the sale of our equity investments in the Colorado and Florida independent power producers in 2004.

All Other

2006 Compared to 2005

Loss Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from All Other increased from a $26 million loss in 2005 to a $128 million loss in 2006. The increase primarily relates to the $136 million after-tax impairment recorded in the third quarter of 2006 related to the sale of the Plaquemine Cogeneration Facility, partially offset by lower interest expense and associated buyback costs related to the redemption of $550 million of senior unsecured notes in April 2005.

2005 Compared to 2004

Loss Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change decreased from a $133 million loss in 2004 to a $26 million loss in 2005. The 2005 results include only one-month of HPL's operations compared to a full year of HPL operations in 2004 due to the sale of HPL in January of 2005. We also resolved a portion of our outstanding Enron litigation in 2005 resulting in a net of tax settlement cost of approximately $28 million.

AEP System Income Taxes

Income Tax Expense increased $55 million between 2005 and 2006 primarily due to an increase in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis and the recording of tax reserve adjustments.

Income Tax Expense decreased $142 million between 2004 and 2005 primarily due to a decrease in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis, offset in part by the recording of the tax return adjustments.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2006, we maintained our strong financial condition as reflected by the following actions and events:

- We maintained stable credit ratings across the AEP System including our rated subsidiaries;
- We issued $1.74 billion of securitization bonds for Texas stranded costs; and
- Standard and Poor's improved our business risk profile rating from six to five.

Debt and Equity Capitalization

	December 31, 2006		December 31, 2005	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 13,698	59.1%	$ 12,226	57.2%
Short-term Debt	18	0.0	10	0.0
Total Debt	13,716	59.1	12,236	57.2
Common Equity	9,412	40.6	9,088	42.5
Preferred Stock	61	0.3	61	0.3
Total Debt and Equity Capitalization	$ 23,189	100.0%	$ 21,385	100.0%

As a consequence of the capital changes during 2006, primarily the issuance of the securitization bonds and the adoption of SFAS 158, our ratio of debt to total capital increased from 57.2% to 59.1%.

In September 2006, the FASB issued SFAS 158 related to phase one of its pension and postretirement benefit accounting project. The new standard requires the recognition of a liability for pension and postretirement benefit plans, thereby eliminating on the balance sheet the SFAS 87 and SFAS 106 deferral and amortization of net actuarial gains and losses. The adoption during the fourth quarter of 2006 resulted in a negative impact on our common equity at December 31, 2006 due to the recognition of a $235 million net of tax accumulated other comprehensive income reduction to common equity for those jurisdictions where we could not record a regulatory asset.

Liquidity

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

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2006, our available liquidity was approximately $3.3 billion as illustrated in the table below:

	Amount	Maturity
	(in millions)	
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	March 2010
Revolving Credit Facility	1,500	April 2011
Total	3,000	
Cash and Cash Equivalents	301	
Total Lquidity Sources	3,301	
Less: Letters of Credit Drawn	26	
Net Available Liquidity	$ 3,275	

In 2006, we amended the terms and increased the size of our credit facilities from $2.7 billion to $3 billion on terms more economically favorable than the previous agreements. The amended facilities are structured as two $1.5 billion credit facilities, each with an option to issue up to $200 million as letters of credit.

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 December 31, 2006, this contractually-defined percentage was 54.0%. Nonperformance of these covenants could result in an event of default under these credit agreements. At December 31, 2006, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the outstanding amounts payable.

The two revolving credit facilities do not contain a material adverse change clause in the event of a draw on either facility.

Under a regulatory order, our utility subsidiaries, other than TCC, cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% of its capital. In addition, this order restricts those utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization. At December 31, 2006, all applicable utility subsidiaries complied with this order.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At December 31, 2006, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 387 consecutive quarters. The Board of Directors increased the quarterly dividend from $0.37 to $0.39 per share in October 2006. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time.

Credit Ratings

Our current credit ratings are as follows:

	Moody's	S&P	Fitch
AEP Short Term Debt	P-2	A-2	F-2
AEP Senior Unsecured Debt	Baa2	BBB	BBB

If we or any of our 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 rating agencies listed above, our borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Managing our cash flows is a major factor in maintaining our liquidity strength.

	2006	2005	2004
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 401	$ 320	$ 778
Net Cash Flows From Operating Activities	2,732	1,877	2,711
Net Cash Flows Used For Investing Activities	(3,743)	(1,005)	(329)
Net Cash Flows From (Used For) Financing Activities	911	(791)	(2,840)
Net Increase (Decrease) in Cash and Cash Equivalents	(100)	81	(458)
Cash and Cash Equivalents at End of Period	$ 301	$ 401	$ 320

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to meet other short-term cash needs. We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2006, we had credit facilities totaling $3 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2006 was $325 million. The weighted-average interest rate of our commercial paper during 2006 was 4.96%. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of common stock or long-term debt and sale-leaseback or leasing agreements. Utility Money Pool borrowings and external borrowings may not exceed authorized limits under regulatory orders. See the discussion below for further detail related to the components of our cash flows.

Operating Activities

	2006	2005	2004
		(in millions)	
Net Income	$ 1,002	$ 814	$ 1,089
Less: Discontinued Operations, Net of Tax	(10)	(27)	(83)
Income Before Discontinued Operations	992	787	1,006
Noncash Items Included in Earnings	1,535	1,494	1,315
Changes in Assets and Liabilities	205	(404)	390
Net Cash Flows From Operating Activities	$ 2,732	$ 1,877	$ 2,711

Net Cash Flows From Operating Activities increased in 2006 because we did not make a pension contribution in 2006 compared with a $626 million contribution in 2005 and increased recovery of deferred fuel. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of increased fuel costs.

Net Cash Flows From Operating Activities were approximately $2.7 billion in 2006 consisting primarily of Income Before Discontinued Operations of $992 million. Income Before Discontinued Operations included noncash expense items primarily for depreciation, amortization, accretion, deferred taxes and deferred investment tax credits. Under-recovered fuel costs decreased due to recoveries under proceedings we initiated in Oklahoma, Texas, Virginia and Arkansas during 2005. 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 is a $232 million decrease in cash related to customer deposits held for trading activities generally due to lower gas and power market prices.

Net Cash Flows From Operating Activities were approximately $1.9 billion in 2005. We produced Income Before Discontinued Operations of $787 million. Income Before Discontinued Operations included noncash expense items primarily for depreciation, amortization, accretion, deferred taxes and deferred investment tax credits. We made contributions of $626 million to our pension trusts. Under-recovered fuel costs increased due to the higher cost of fuel, especially natural gas. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of our increased fuel costs. 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 a $140 million cash increase from Accounts Payable due to higher fuel and allowance acquisition costs not paid at December 31, 2005 and an increase in Customer Deposits held for trading activities of $157 million related to market prices.

Net Cash Flows From Operating Activities were $2.7 billion in 2004 consisting of our Income Before Discontinued Operations of $1 billion and noncash charges of $1.6 billion for depreciation, amortization and deferred taxes. We recorded $302 million in noncash income for carrying costs on Texas stranded cost recovery and recognized an after-tax, noncash Extraordinary Loss of $121 million to provide for probable disallowances to TCC's stranded generation costs. We realized gains of $157 million on sales of assets, primarily the IPPs and our South Coast equity investment. We made $231 million of contributions to our pension trusts. Changes in Assets and Liabilities represent those items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Changes in working capital items resulted in cash from operations of $430 million predominantly due to increased accrued income taxes. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since our consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments.

Investing Activities

	2006	2005	2004
		(in millions)	
Construction Expenditures	$ (3,528)	$ (2,404)	$ (1,637)
Change in Other Temporary Cash Investments, Net	(33)	76	32
Investment in Discontinued Operations, Net	-	-	(59)
Purchases/Sales of Investment Securities, Net	(279)	98	46
Acquisitions of Assets	-	(360)	-
Proceeds from Sales of Assets	186	1,606	1,357
Other	(89)	(21)	(68)
Net Cash Flows Used for Investing Activities	$ (3,743)	$ (1,005)	$ (329)

Net Cash Flows Used For Investing Activities were $3.7 billion in 2006 primarily due to Construction Expenditures for our environmental investment plan. In our normal course of business, we purchase investment securities including auction rate securities and variable rate demand notes with cash available for short-term investments. These amounts also include purchases and sales of securities within our nuclear trusts.

Net Cash Flows Used For Investing Activities were $1.0 billion in 2005 primarily due to Construction Expenditures being partially offset by the proceeds from the sales of HPL and STP. The sales were part of an announced plan to divest noncore investments and assets and a requirement of collecting stranded costs in Texas. Construction Expenditures increased due to our environmental investment plan.

Net Cash Flows Used For Investing Activities were $329 million in 2004. We funded our construction expenditures primarily with cash generated by operations. Our construction expenditures of $1.6 billion were distributed across our system, of which the most significant expenditures were investments for environmental improvements of $350 million and for a high voltage transmission line of $75 million. During 2004, we sold our U.K. generation, Jefferson Island Storage, LIG and certain IPP and TCC generation assets and used the proceeds from the sales of these assets to reduce debt.

We forecast approximately $3.5 billion of construction expenditures for 2007 plus $427 million for announced purchases of gas-fired generating units. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. These construction expenditures will be funded through results of operations and financing activities.

Financing Activities

	2006	2005	2004
		(in millions)	
Issuance of Common Stock	$ 99	$ 402	$ 17
Repurchase of Common Stock	-	(427)	-
Issuance/Retirement of Debt, Net	1,420	(91)	(2,238)
Dividends Paid on Common Stock	(591)	(553)	(555)
Other	(17)	(122)	(64)
Net Cash Flows From (Used for) Financing Activities	$ 911	$ (791)	$ (2,840)

Net Cash Flows From Financing Activities were $911 million in 2006 primarily due to issuance of the Texas Securitization Bonds. We paid common stock dividends of $591 million and issued and retired debt securities. See Note 15.

In 2005, we used $791 million of cash to pay dividends, buy back stock, retire preferred stock and reduce debt.

In 2004, we used $2.8 billion of cash to reduce debt and pay common stock dividends. We achieved our goal of reducing debt below 60% of total capitalization by December 31, 2004. The debt reductions were primarily funded with proceeds from our various divestitures during 2004.

The following financing activities occurred during 2006:

Common Stock:

- During 2006, we issued 2,955,898 shares of common stock under our incentive compensation and dividend reinvestment plans and received net proceeds of $99 million.

Debt:

- During 2006, we issued approximately $3.4 billion of long-term debt, including approximately $264 million of pollution control revenue bonds, $1.4 billion of senior notes and $1.7 billion of securitization bonds for Texas stranded costs. The proceeds from these issuances were used to fund long-term debt maturities and optional redemptions and construction programs.
- During 2006, we entered into $898 million of interest rate derivatives and settled $1.2 billion of such transactions. The settlements resulted in a net cash expenditure of $8 million. As of December 31, 2006, we had in place interest rate derivatives designated as cash flow hedges with a notional amount of $200 million in order to hedge a portion of anticipated 2007 issuances.
- At December 31, 2006, we had credit facilities totaling $3 billion to support our commercial paper program. As of December 31, 2006, we had no commercial paper outstanding related to the corporate borrowing program. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $325 million in March 2006 and the weighted average interest rate of commercial paper outstanding during the year was 4.96%.

Our capital investment plans for 2007 will require additional funding from the capital markets.

Off-balance Sheet Arrangements

Under a limited set of circumstances, 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 guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements and sales of customer accounts receivable that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements:

AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. We have no ownership interest in the commercial paper conduits and, in accordance with GAAP, are not required to consolidate these entities. We continue to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables, and accelerate AEP Credit's cash collections.

AEP Credit's sale of receivables agreement expires August 24, 2007. We intend to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2006, $536 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent receivables purchased by AEP Credit from certain Registrant Subsidiaries. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivables less an allowance for anticipated uncollectible accounts.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $1.2 billion as of December 31, 2006.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 14. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years. At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years; (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value; or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. We intend to renew the lease for the full twenty years. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the current lease term from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2006, the maximum potential loss was approximately $31 million ($20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. We have other railcar lease arrangements that do not utilize this type of financing structure.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payments Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Short-term Debt (a)	$ 18	$ -	$ -	$ -	$ 18
Interest on Fixed Rate Portion of Long-term Debt (b)	619	1,144	981	5,244	7,988
Fixed Rate Portion of Long-term Debt (c)	1,126	1,050	1,823	8,162	12,161
Variable Rate Portion of Long-term Debt (d)	143	85	88	1,277	1,593
Capital Lease Obligations (e)	90	117	43	126	376
Noncancelable Operating Leases (e)	331	599	490	1,893	3,313
Fuel Purchase Contracts (f)	2,499	3,892	3,090	8,299	17,780
Energy and Capacity Purchase Contracts (g)	199	352	306	408	1,265
Construction Contracts for Capital Assets (h)	1,728	645	29	945	3,347
Total	$ 6,753	$ 7,884	$ 6,850	$ 26,354	$ 47,841

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See Note 15. Represents principal only excluding interest.
(d) See Note 15. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.50% and 6.35% at December 31, 2006.
(e) See Note 14.
(f) Represents contractual obligations to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 9 to the consolidated financial statements, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trusts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. At December 31, 2006, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millions)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Standby Letters of Credit (a) (b)	$ 26	$ -	$ -	$ -	$ 26
Guarantees of the Performance of Outside Parties (b)	-	-	-	85	85
Guarantees of Our Performance (c)	1,943	1,376	7	20	3,346
Transmission Facilities for Third Parties (d)	21	12	-	-	33
Total Commercial Commitments	$ 1,990	$ 1,388	$ 7	$ 105	$ 3,490

(a) We issue standby letters of credit to third parties. These letters of credit, issued in our ordinary course of business, cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. The maximum future payments of these letters of credit are $26 million with maturities ranging from March 2007 to November 2007. As the parent of all of these subsidiaries, AEP holds all assets of the subsidiaries as collateral. There is no recourse to third parties if these letters of credit are drawn.
(b) See "Guarantees of Third-party Obligations" section of Note 6.
(c) We issued performance guarantees and indemnifications for energy trading, International Marine Terminal Pollution Control Bonds and various sale agreements.
(d) As construction agent for third party owners of transmission facilities, we committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to $8 million and other remedies required by contract terms.

Other

Cook Plant

In 2006, during a regular refueling outage, Cook Plant Unit 1 completed the planned replacement of major components, including the reactor vessel head, at a cost of $119 million. These improvements and replacement of major components should increase efficiency as well as adding 40 MW of capacity in the winter. We refueled Cook Plant Unit 2 during March and April 2006 and plan to replace its vessel head during its next refueling outage scheduled for the fall of 2007.

Texas REPs

As part of the purchase-and-sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings with Centrica from the two REPs above a threshold amount through 2006 if the Texas retail market developed increased earnings opportunities. In 2005, upon resolution of various contractual matters with Centrica, we received payments from our share in earnings of $45 million and $70 million for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in 2005. In 2006, we received a $70 million payment for our share in earnings of 2005. The 2006 payment is contingent on Centrica's operating results, contractually capped at $20 million, and, to the extent earned, we expect to receive the 2006 payment in March 2007.

SIGNIFICANT FACTORS

Electric Transmission Texas LLC Joint Venture

In January 2007, we signed a participation agreement with MidAmerican Energy Holdings Company (MidAmerican) to form a joint venture company, Electric Transmission Texas LLC (ETT), to fund, own and operate electric transmission assets in ERCOT. ETT filed with the PUCT in January 2007 requesting regulatory approval to operate as an electric transmission utility in Texas, to transfer from TCC to ETT approximately $76 million of transmission assets currently under construction and to establish a wholesale transmission tariff for ETT. ETT also requested approval from PUCT of initial rates based on an 11.25% return on equity.

Upon receipt of all required regulatory approvals, AEP Utilities, Inc., a subsidiary of AEP, and MEHC Texas Transco LLC, a subsidiary of MidAmerican, each will acquire a 50 percent equity ownership in ETT. AEP and MidAmerican plan for ETT to invest in additional transmission projects in ERCOT. The joint venture partners anticipate in excess of $1 billion in projects could be made by ETT during the next several years.

TCC also made a regulatory filing at the FERC in February 2007 regarding the transfer of certain transmission assets from TCC to ETT. In February 2007, ETT filed a proposal with the PUCT that addresses the Competitive Renewable Energy Zone initiative of the Texas legislature. The proposal outlines opportunities for additional significant investment in transmission assets in Texas. The joint venture is anticipated to begin operations in the second half of 2007, subject to regulatory approval from the PUCT and the FERC.

We believe Texas can provide a high degree of regulatory certainty for transmission investment due to the predetermination of ERCOT's need based on reliability needs and significant Texas economic growth as well as public policy that supports "green generation" initiatives, which require transmission access. In addition, a streamlined annual interim transmission cost of service review process is available in ERCOT, which should help reduce regulatory lag. The use of a joint venture structure will allow us to share the capital requirements for this type of significant investment while allowing us to participate in more transmission projects than previously anticipated.

AEP Interstate Project

In January 2006, we filed a proposal with the FERC and PJM to build a new 765 kV 550-mile transmission line from West Virginia to New Jersey. The 765 kV line is designed to reduce PJM congestion costs by substantially improving west-east transfer capability by approximately 5,000 MW during peak loading conditions and reducing transmission line losses by up to 280 MW. The project would also enhance reliability of the Eastern transmission grid. A new subsidiary, AEP Transmission Co., LLC, will own the line and undertake construction of the project. The projected cost for the project is approximately $3 billion, of which ownership may ultimately be shared with third party affected participants. The project is subject to PJM, state and FERC approvals of appropriate incentive cost recovery mechanisms. The projected in-service date assumes eight years for siting and construction. Due to delays in approval by the PJM stakeholder process, the projected in-service date is now 2015. This assumes approval by PJM in mid-2007, followed by approval by FERC on initial rates by the end of 2007.

We were the first entity to file with the Department of Energy (DOE) seeking to have the route of a proposed transmission project designated as a National Interest Electric Transmission Corridor (NIETC). The Energy Policy Act of 2005 provides for NIETC designation for areas experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers. In August 2006, the DOE issued the "National Interest Electric Transmission Congestion Study." In this study, DOE indicated that the mid-Atlantic Coastal area, which the AEP Interstate Project is designed to reinforce, is one of the two most critical congestion areas in the nation. This finding should help us obtain early NIETC Designation as promulgated by the Energy Policy Act of 2005. In October 2006, we filed comments with the DOE encouraging corridor designation that is consistent with the proposed line.

In July 2006, pursuant to our request, the FERC clarified that the project qualifies for incentive rate treatment, provided that the new line is included in PJM's formal Regional Transmission Expansion Plan to be finalized in 2007. The conditionally approved incentives include (a) a return on equity set at the high end of the "zone of reasonableness"; (b) the timely recovery of the cost of capital during the construction period; and (c) the ability to defer and recover costs incurred during the pre-construction and pre-operating period. Since the FERC has clarified that the project qualifies for these rate incentives, we expect to propose rates that will capture the incentives in a future FERC rate filing.

Texas Restructuring

Texas Restructuring Legislation established customer choice on January 1, 2002 and allowed electric utility companies to file for recovery of securitizable stranded generation plant costs, generation related regulatory assets and non-securitizable other restructuring true-up items. These recoverable and refundable items were recorded as true-up regulatory assets and liabilities.

TCC will recover its PUCT approved net true-up regulatory asset under the Texas Restructuring Legislation using two mechanisms: (a) by issuing securitization bonds in the amount of its net stranded generation costs and implementing a transition charge (TC) rate rider to collect the bond interest and principal over the term of the bonds and (b) by implementing a credit competition transition charge (CTC) rate rider to refund its net regulatory liability for other true-up items.

In February 2006, the PUCT issued an order in TCC's True-up Proceeding, which determined that TCC's recoverable net true-up regulatory asset, for both securitizable net stranded generation cost regulatory assets and net other true-up items regulatory liabilities, was $1.475 billion as of September 30, 2005. The order disallowed specific items which included, among other things, a significant portion of TCC's wholesale capacity auction true-up revenues and a portion of TCC's stranded costs determined from the sale of the ERCOT generating units.

TCC appealed the PUCT true-up orders seeking relief in both state and federal court on the grounds that the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. The significant items appealed by TCC are:

- The PUCT ruling that TCC did not comply with the statute and PUCT rules regarding the required auction of 15% of its Texas jurisdictional installed capacity, which led to a significant disallowance of capacity auction true-up revenues,
- The PUCT ruling that TCC acted in a manner that was commercially unreasonable, because it failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and it bundled out of the money gas units with the sale of its coal unit, which led to the disallowance of a significant portion of TCC's net stranded generation plant cost, and
- The two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation. See "TCC and TNC Deferred Fuel" and "TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" sections of Note 4.

Municipal customers and other intervenors appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries. On February 1, 2007 the Texas District Court judge hearing the various appeals issued a letter containing his preliminary determinations. He generally affirmed the PUCT's April 4, 2006 final True-up order with two significant exceptions. The judge determined that the PUCT erred when it determined TCC's stranded cost using the sale of assets method instead of the Excess Cost Over Market (ECOM) method to value TCC's nuclear plant. The judge also determined that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. However, the District Court did not rule that the carrying cost rate was inappropriate. He directed that these matters should be remanded to the PUCT to determine their specific impact on TCC's future revenues.

In response to a request by TCC, the District Court judge will hear additional argument on March 22, 2007 regarding use of the ECOM method to value TCC's nuclear plant stranded cost. TCC anticipates that the final judgment will be entered after that hearing. TCC intends to appeal any final adverse rulings of the District Court regarding these two matters along with certain of the judge's other preliminary determinations that affirm the PUCT's decisions. It is possible that the PUCT could also appeal any final adverse rulings regarding these two matters.

Although management cannot predict the ultimate outcome of these preliminary District Court determinations, any future remanded PUCT proceedings or any future court appeals, management has concluded that it is probable that the District Court's preliminary ruling regarding the use of an ECOM method in lieu of a sales method to determine securitizable stranded cost will not be upheld on appeal. The judge has also determined in his letter ruling that if the sales method is permitted for valuing the nuclear plant, the PUCT improperly reduced stranded costs in connection with the sales process, which could have a materially favorable effect on TCC.

Management also concluded if the District Court's preliminary carrying cost rate ruling is ultimately remanded to the PUCT for reconsideration, the PUCT could either confirm the existing carrying cost rate or redetermine the rate. If the PUCT changes the rate, it could result in a material adverse change to TCC's recoverable carrying costs. However, management cannot predict what actions, if any, the PUCT will take regarding the carrying costs.

If the District Court judge's original determination that TCC used an improper method to value its stranded costs is ultimately upheld on appeal, it could substantially reduce TCC's stranded costs. We cannot estimate the amount at this time, but the amount could exceed TCC's Common Shareholder's Equity at December 31, 2006. If it were finally concluded that the ECOM method must be used to value TCC's nuclear plant stranded cost, and/or that the PUCT's rule on carrying costs was invalid, it could, after the PUCT remand decisions, have a substantial adverse impact on future results of operations, cash flows and financial condition.

If TCC ultimately succeeds in its appeals on other than the above two matters, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, including their appeals of the two matters discussed above, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

SECA Revenue Subject to Refund

We eliminated through-and-out transmission service (T&O) revenues in accordance with FERC orders and implemented SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. In August 2006, the ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made.

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. The AEP East companies have reached settlements with certain customers related to approximately $70 million of such revenues. The unsettled gross SECA revenues total approximately $150 million. If the ALJ's initial decision is upheld in its entirety, it would disallow $126 million of the AEP East companies' unsettled gross SECA revenues. The AEP East companies have provided a reserve for $37 million in net refunds.

We, together with Exelon and the Dayton Power and Light Company, filed an extensive post hearing brief and reply brief noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. We believe that the FERC should reject the initial decision because it is contrary to prior related FERC decisions, which are presently subject to rehearing. Furthermore, we believe the ALJ's findings on key issues are largely without merit. However, the initial decision is adversely impacting settlement negotiations. Although we believe we have meritorious arguments, management cannot predict the ultimate outcome of any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision, it will have an adverse effect on future results of operations and cash flows.

Virginia Restructuring

In February 2007, the Virginia legislature adopted amendments to its electric restructuring law. The amendments would shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation supply would return to a form of cost-based regulation. The Governor of Virginia has not yet signed this legislation. We are in the process of evaluating the impact of the legislation if it is signed into law.

New Generation

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 629 MW IGCC power plant using clean-coal technology. The application proposed cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $24 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover construction-financing costs through regulatory authorization until the plant is placed in service. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their RSPs. In Phase 3, which begins when the plant enters commercial operation and runs through the operating life of the plant, the Ohio companies would recover or refund in distribution rates any difference between the Ohio companies' market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected $1.2 billion cost of the plant along with fuel, consumables and replacement power costs. Through December 31, 2006, the Ohio companies deferred $20 million of pre-construction IGCC costs, of which they have recovered $12 million. The PUCO indicated that if the Ohio companies have not commenced continuous construction of the IGCC plant by 2010, all charges collected for pre-construction costs, which are assignable to other jurisdictions, must be refunded to Ohio ratepayers with interest.

In January 2006, APCo filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer generating station in Mason County, West Virginia. In January 2007, the WVPSC issued an order granting APCo's motion to delay the Commission's statutory deadline for issuing an order on the certificate for the construction of the proposed IGCC plant. The WVPSC approved a deadline of December 3, 2007. Through December 31, 2006, APCo deferred pre-construction IGCC costs totaling $10 million.

In December 2005, SWEPCo sought proposals for new peaking, intermediate and base load generation to be online between 2008 and 2011. In May 2006, SWEPCo announced plans to construct new generation to satisfy the demands of its customers. SWEPCo will build up to 480 MW of simple-cycle natural gas combustion turbine peaking generation in Tontitown, Arkansas and will build a 480 MW combined-cycle natural gas fired plant at its existing Arsenal Hill Power Plant in Shreveport, Louisiana. SWEPCo also plans to build a new 600 MW base load coal plant, of which SWEPCo's investment will be 73%, in Hempstead County, Arkansas by 2011 to meet the long-term generation needs of its customers. Preliminary cost estimates for SWEPCo's share of the new facilities are approximately $1.4 billion (this total excludes the related transmission investment and AFUDC). These new facilities are subject to regulatory approvals from SWEPCo's three state commissions. The peaking generation facility in Tontitown, Arkansas has been approved by all three state commissions and Units 3 and 4 are projected to be online in July 2007 and the remaining two units by 2008. Construction is expected to begin in 2007 on the intermediate and base load facilities upon approval from the state regulatory commissions. Expenditures related to construction of these facilities are expected to total $349 million in 2007.

In September 2005, PSO sought proposals for new peaking generation to be online in 2008, and in December 2005 PSO sought proposals for base load generation to be online in 2011. PSO received proposals and evaluated those proposals meeting the Request for Proposal criteria with oversight from a neutral third party. In March 2006, PSO announced plans to add 170 MW of peaking generation to its Riverside Station plant in Jenks, Oklahoma where PSO will construct and operate two 85 MW simple-cycle natural gas combustion turbines. Also in March 2006, PSO announced plans to add 170 MW of peaking generation to its Southwestern Station plant in Anadarko, Oklahoma where they will construct and operate two 85 MW simple-cycle natural gas combustion turbines. Combined preliminary cost estimates for these additions are approximately $120 million. In July 2006, PSO announced plans to enter a joint venture with Oklahoma Gas and Electric Company (OG&E) and Oklahoma Municipal Power Authority (OMPA) where OG&E will construct and operate a new 950 MW coal-fueled electricity generating unit near Red Rock, Oklahoma. PSO will own 50% of the new unit. PSO, OG&E and OMPA signed an agreement in February 2007 with Red Rock Power Partners to begin the first phase of the project. Preliminary cost estimates for 100% of the new facility are approximately $1.8 billion, and the unit is expected to be online no later than the first half of 2012. These new facilities are subject to regulatory approval from the OCC. Construction of all of these additions is expected to begin in 2007. Expenditures related to construction of these facilities are expected to total $125 million in 2007.

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the first half of 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for approximately $325 million and the assumption of liabilities of approximately $2 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the second quarter of 2007. The Lawrenceburg plant is located in Lawrenceburg, Indiana, adjacent to I&M's Tanners Creek Plant, and is a natural gas, combined cycle power plant with a generating capacity of 1,096 MW.

Pension and Postretirement Benefit Plans

We maintain qualified, defined benefit pension plans (Qualified Plans), which cover a substantial majority of nonunion and certain union employees, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans, collectively the Pension Plans. Additionally, we entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits as a part of the nonqualified, supplemental plans. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Qualified Plans and Postretirement Plans are collectively the Plans.

The following table shows the net periodic cost for the Pension Plans and Postretirement Plans:

	Years Ended December 31,		
	2006	**2005**	**2004**
Net Periodic Benefit Cost		**(in millions)**	
Pension Plans	$ 71	$ 61	$ 40
Postretirement Plans	96	109	141
Assumed Rate of Return			
Pension Plans	8.50%	8.75%	8.75%
Postretirement Plans	8.00%	8.37%	8.35%

The net periodic cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plans' assets. In developing the expected long-term rate of return assumption, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. We also considered historical returns of the investment markets as well as our ten-year average return, for the period ended December 2006, of approximately 9.43%. We anticipate that the investment managers we employ for the Plans will generate long-term returns averaging 8.50%.

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

	Pension		Other Postretirement Benefit Plans		
	2006 Actual Asset Allocation	2007 Target Asset Allocation	2006 Actual Asset Allocation	2007 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return
Equity	63%	65%	66%	65%	10.00%
Real Estate	6%	5%	-%	-%	8.25%
Fixed Income	26%	28%	32%	33%	5.25%
Cash and Cash Equivalents	5%	2%	2%	2%	4.25%
Total	100%	100%	100%	100%	

	Pension	Other Postretirement Benefit Plans
Overall Expected Return (weighted average)	8.50%	8.00%

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 8.50% and 8.00% for the Pension Plans and Postretirement Plans, respectively, are reasonable long-term rates of return on the Plans' assets despite the recent market volatility. The Plans' assets had an actual gain of 12.78% and 7.76% for the twelve-months ended December 31, 2006 and 2005, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2006, we had cumulative gains of approximately $187 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains will result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2006 under this method was 5.75% for the Pension Plans and 5.85% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 8.50%, a discount rate of 5.75% and various other assumptions, we estimate that the pension costs for all pension plans will approximate $40 million, $14 million and $5 million in 2007, 2008 and 2009, respectively. Based on an expected rate of return on the OPEB plans' assets of 8.00%, a discount rate of 5.85% and various other assumptions, we estimate Postretirement Plan costs will approximate $85 million, $81 million and $78 million in 2007, 2008 and 2009, respectively. Future actual cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in "Pension and Other Postretirement Benefits" within the "Critical Accounting Estimates" section of this Management's Financial Discussion and Analysis of Results of Operations.

The value of the Pension Plans' assets increased to $4.3 billion at December 31, 2006 from $4.1 billion at December 31, 2005 primarily due to investment returns on the assets. The Qualified Plans paid $267 million in benefits to plan participants during 2006 (nonqualified plans paid $9 million in benefits). The value of our Postretirement Plans' assets increased to $1.3 billion at December 31, 2006 from $1.2 billion at December 31, 2005. The Postretirement Plans paid $112 million in benefits to plan participants during 2006.

Our nonqualified pension plans are unfunded, and are therefore considered underfunded for accounting purposes. For the nonqualified pension plans, the accumulated benefit obligation in excess of plan assets was $78 million and $81 million at December 31, 2006 and 2005, respectively. We made a contribution of $626 million in 2005 to meet our goal of fully funding all Qualified Plans by the end of 2005. Our Qualified Plans remained fully funded as of December 31, 2006.

Certain pension plans we sponsor and maintain contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act of 1967, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. We believe that our defined benefit pension plans comply with the applicable requirements of such laws.

The Pension Protection Act of 2006 did not materially impact our plans.

Litigation

In the ordinary course of business, we, along with our subsidiaries, are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what their eventual outcome will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases that have a probable likelihood of loss and if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our results of operations.

See discussion of the Environmental Litigation within the "Environmental Matters" section of "Significant Factors."

Environmental Matters

We are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

- Requirements under the Clean Air Act (CAA) to reduce emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter (PM) and mercury from fossil fuel-fired power plants; and
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain of our power plants.

In addition, we are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of spent nuclear fuel and future decommissioning of our nuclear units. We are also monitoring possible future requirements to reduce carbon dioxide (CO_2) emissions to address concerns about global climate change. All of these matters are discussed below.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality, and control mobile and stationary sources of air emissions. The major CAA programs affecting our power plants are described below. The states in which we operate, implement and administer many of these programs and could impose additional or more stringent requirements.

National Ambient Air Quality Standards: The CAA requires the Federal EPA to periodically review the available scientific data for six criteria pollutants and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra safety margin. These concentration levels are known as "national ambient air quality standards" or NAAQS.

Each state identifies those areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. In addition, as the Federal EPA reviews the NAAQS, the attainment status of areas can change, and states may be required to develop new SIPs. The Federal EPA recently proposed a new PM NAAQS and is conducting periodic reviews for additional criteria pollutants.

In 1997, the Federal EPA established new NAAQS that required further reductions in SO_2 and NO_x emissions. In 2005, the Federal EPA issued a final model federal rule, the Clean Air Interstate Rule (CAIR), that assists states developing new SIPs to meet the new NAAQS. CAIR reduces regional emissions of SO_2 and NO_x from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO_2 by 50 percent by 2010, and by 65 percent by 2015. NO_x emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70 percent from current levels by 2015. Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. The Federal EPA affirmed certain aspects of the final CAIR after reconsideration. The rule has been challenged in the courts. States were required to develop and submit SIPs to implement CAIR by November 2006. Nearly all of the states in which our power plants are located will be covered by CAIR. Oklahoma is not affected, while Texas and Arkansas will be covered only by certain parts of CAIR. A SIP that complies with CAIR will also establish compliance with other CAA requirements, including certain visibility goals.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the Federal EPA issued a final Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO_2 and NO_x emissions in order to comply with CAIR. The Federal EPA affirmed certain aspects of the final CAMR after reconsideration, and the rule has been challenged in the courts. States were required to develop and submit their SIPs to implement CAMR by November 2006.

The Acid Rain Program: The 1990 Amendments to the CAA include a cap-and-trade emission reduction program for SO_2 emissions from power plants, implemented in two phases. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year. The 1990 Amendments also contain requirements for power plants to reduce NOx emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. We continue to meet our obligations under the Acid Rain Program through the installation of controls, use of alternate fuels and participation in the emissions allowance markets. CAIR uses the SO_2 allowances originally allocated through the Acid Rain Program as the basis for its SO_2 cap-and-trade system.

Regional Haze: The CAA establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment of visibility in these areas (the "Regional Haze" program). In 2005, the Federal EPA issued its final Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration that CAIR will result in more visibility improvements than BART for power plants subject to it. Thus, states are allowed to substitute CAIR requirements in their Regional Haze SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states not subject to CAIR requirements for SO_2 and NO_x, some additional controls will be required. The courts upheld the final rule.

Estimated Air Quality Environmental Investments

The CAIR and CAMR programs described above require us to make significant additional investments, some of which are estimable. However, many of the rules described above have been challenged in the courts and are not incorporated into SIPs. As a result, these rules may be further modified. Our estimates are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation; required levels of reductions; methods for allocation of allowances; and our selected compliance alternatives. In short, we cannot estimate our compliance costs with certainty and the actual costs to comply could differ significantly from the estimates discussed below.

We installed a total of 9,700 MW of selective catalytic reduction (SCR) technology to control NO_x emissions at our eastern power plants over the past several years to comply with NO_x requirements in various SIPs. We comply with Acid Rain Program SO_2 requirements by installing scrubbers, using alternate fuels and using SO_2 allowances. We receive allowances through Acid Rain Program allocations and purchase them at the annual Federal EPA auction or in the market. Decreasing allowance allocations, our diminishing SO_2 allowance bank and increasing allowance costs will require us to install additional controls on our power plants. In addition under CAIR and CAMR, we will be required to install additional controls by 2010. We plan to install additional scrubbers on 7,300 MW for SO_2 control and additional SCRs on 1,900 MW for NO_x control to comply with current CAIR and CAMR requirements. In January 2007, the scrubber on Unit 2 of Mitchell Plant went into service leaving 6,500 MW of scrubbers to be completed. From 2007 to 2011, we estimate total environmental investment of $2.2 billion including investment in scrubbers and other SO_2 equipment of approximately $1.4 billion. We will also incur additional operation and maintenance expenses in future years due to the costs associated with the maintenance of additional controls, disposal of byproducts and purchase of reagents.

Assuming that the CAIR and CAMR programs are implemented consistent with the provisions of the final federal rules, we expect to incur additional costs for pollution control technology retrofits between 2012 and 2020 of approximately $2.6 billion. However, this estimate is highly uncertain due to the variability associated with: (1) the states' implementation of these regulatory programs, including the potential for SIPs that impose standards more stringent than CAIR or CAMR; (2) the actual performance of the pollution control technologies installed on our units; (3) changes in costs for new pollution controls; (4) new generating technology developments; and (5) other factors. Associated operational and maintenance expenses will also increase during those years. We cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.

We will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Clean Water Act Regulations

In 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen or entrained in the cooling water. The standards vary based on the water bodies from which the plants draw their cooling water. These rules will result in additional capital and operating expenses, which the Federal EPA estimated could be $193 million for our plants. Any capital costs incurred to meet these standards had been expected to be incurred between 2008 and 2010. We undertook site-specific studies and have been evaluating site-specific compliance or mitigation measures that could significantly change these cost estimates. In addition, a recent court decision introduced additional uncertainty to these costs and their timing.

The rule was challenged in the courts by states, advocacy organizations and industry. On January 25, 2007, the Second Circuit Court of Appeals issued a decision remanding significant portions of the rule to the Federal EPA. Among other things, the restoration option, the cost-benefit and other tests and certain alternative technology options in the 2004 rule have been remanded. We cannot predict how or when the Federal EPA will respond to the remand, or what effect the remand may have on similar requirements adopted by the states. We may seek further review or relief from the schedules included in the final rule and our permits, in order to allow time for the Federal EPA's response to the remand.

Potential Regulation of CO_2 Emissions

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO_2, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol in 1998, but the treaty was not submitted to the Senate for its advice and consent. In 2001, President Bush announced his opposition to the treaty. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. Members of Congress introduced several bills seeking regulation of greenhouse gas emissions, including CO_2 emissions from power plants, but none have passed. We participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

The Federal EPA stated that it does not have authority under the CAA to regulate greenhouse gas emissions that may affect global climate trends. This decision was upheld by an appellate court. The U.S. Supreme Court reviewed the appellate decision and is expected to issue its decision in 2007.

We will seek recovery of expenditures for potential regulation of CO_2 emissions from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain special interest groups, has been consolidated with the Federal EPA case. Several similar complaints were filed in 1999 and thereafter against nonaffiliated utilities including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees. The alleged modifications at our power plants occurred over a twenty-year period. A bench trial on the liability issues was held during 2005. Briefing has concluded. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

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.

Courts that considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, reached different conclusions. Similarly, courts that considered whether the activities at issue increased emissions from the power plants reached different results. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Court denied the Federal EPA's request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. The Federal EPA also proposed a rule that would define "emissions increases" in a way that would exclude most of the challenged activities from NSR.

We are unable to estimate the loss or range of loss related to any contingent liability, if any, 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 to be determined by the court. If we do not prevail, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

Other Environmental Concerns

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

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated results of operations or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosure relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required: Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with the regulated revenues from our customers in the same accounting period. We also record regulatory liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used: When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We review the probability of recovery whenever new events occur, for example, changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write-off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used: A change in the above assumptions may result in a material impact on our results of operations. Refer to Note 5 of the Notes to Consolidated Financial Statements for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required: We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. In the Arkansas, Louisiana, Oklahoma and Texas jurisdictions, we do not record the fuel portion of unbilled revenue in accordance with the applicable state commission regulatory treatment. This estimate is reversed in the following month and actual revenue is recorded based on meter readings.

Incremental unbilled electric utility revenues included in Revenue on our Consolidated Statements of Income were $(19) million, $28 million and $22 million for the years ended December 31, 2006, 2005 and 2004, respectively. Accrued unbilled revenues for the Utility Operations segment were $329 million and $348 million as of December 31, 2006 and 2005, respectively.

Assumptions and Approach Used: The operating company calculates the monthly estimate for unbilled revenues as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to the occurrence of problems in meter readings, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used: Significant fluctuations in energy demand for the unbilled period, weather impact, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the Accrued Unbilled Revenues on the Balance Sheets.

Revenue Recognition – Accounting for Derivative Instruments

Nature of Estimates Required: Management considers fair value techniques, valuation adjustments related to credit and liquidity, and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used: We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing future bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We base credit adjustments on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings. We evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided in the original documentation related to hedge accounting.

Effect if Different Assumptions Used: There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

The probability that hedged forecasted transactions will occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding accounting for derivative instruments, see sections labeled Credit Risk and VaR Associated with Risk Management Contracts within "Quantitative and Qualitative Disclosures About Risk Management Activities."

Long-Lived Assets

Nature of Estimates Required: In accordance with the requirements of SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria under SFAS 144. The evaluations of long-lived held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Use: The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used: In connection with the evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. In cases of impairment as described in Note 8 of the Notes to Consolidated Financial Statements, we made our best estimate of fair value using valuation methods based on the most current information at that time. We divested certain noncore assets and their sales values can vary from the recorded fair value as described in Note 8 of the Notes to Consolidated Financial Statements. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

Nature of Estimates Required: We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under SFAS 87, "Employers' Accounting For Pensions", SFAS 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" and SFAS 158. See Note 9 of the Notes to Consolidated Financial Statements for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded.

Assumptions and Approach Used: The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Expected return on plan assets
- Health care cost trend rate
- Rate of compensation increase
- Cash balance crediting rate

Other assumptions, such as retirement, mortality, and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used: The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefits Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2006 Benefit Obligations				
Discount Rate	$ (178.2)	$ 192.7	$ (114.1)	$ 121.4
Compensation Increase Rate	27.2	(25.5)	3.3	(3.2)
Cash Balance Crediting Rate	13.4	16.7	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	91.7	(83.7)
Effect on 2006 Periodic Cost				
Discount Rate	(13.0)	13.6	(10.4)	10.6
Compensation Increase Rate	5.9	(5.6)	0.6	(0.6)
Cash Balance Crediting Rate	6.7	(1.9)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	15.2	(14.7)
Expected Return on Plan Assets	(19.7)	19.7	(5.6)	5.7

N/A = Not Applicable

Adoption of New Accounting Pronouncements

Beginning in 2006, we adopted SFAS No. 123 (revised 2004) Share-Based Payment, on a modified prospective basis, resulting in an insignificant favorable cumulative effect of a change in accounting principle. Including stock-based compensation expense related to employee stock options and other share based awards, did not materially affect our quarter-over-quarter and year-to-date net income and earnings per share. We have not granted options as part of our regular stock-based compensation program since 2003. However, we have used options in limited circumstances totaling 149,000 options in 2004, 10,000 options in 2005 and none during 2006. As of December 31, 2006, we have $90 million of total unrecognized compensation cost related to unvested share-based compensation arrangements. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.64 years. See Note 2 in our Notes to Consolidated Financial Statements for further discussion.

New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level and an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. We expect that the adoption of this standard will impact MTM valuations of certain contracts, but are unable to quantify the effect at this time. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. We will adopt SFAS 157 effective January 1, 2008.

In July 2006, the FASB issued FIN 48. It clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. FIN 48 is effective for fiscal years beginning after December 15, 2006. We estimate the effect of this interpretation on our financial statements to be an unfavorable adjustment to retained earnings of less than $15 million.

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. In the event we elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. We will adopt SFAS 159 effective January 1, 2008.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity, coal and emission allowances, our Utility Operations segment is exposed to certain market risks. These risks include commodity price risk, interest rate risk and credit risk. In addition, we may be exposed to foreign currency exchange risk because occasionally we procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

All Other includes gas operations which holds forward gas contracts that were not sold with the gas pipeline and storage assets. These contracts are primarily financial derivatives, along with physical contracts, which will gradually liquidate and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

In 2006, our Generation and Marketing segment holds power sale contracts to commercial and industrial customers in ERCOT. In 2007, the Generation and Marketing segment will also own wholesale power trading and marketing contracts within ERCOT. The wholesale ERCOT trading and marketing activity was previously reflected in AEP's Utility Operations segment.

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, coal, and emissions and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy and monitored by the Chief Risk Officer and risk management staff. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

We have 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 various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, senior executives, and other 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 predominantly of 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 embrace the disclosure standards applicable to our business activities. The following tables provide information on our risk management activities.

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

The following two tables summarize the various mark-to-market (MTM) positions included on our balance sheet as of December 31, 2006 and the reasons for changes in our total MTM value included on our balance sheet as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet December 31, 2006 (in millions)

	Utility Operations	Generation and Marketing	All Other	Sub-Total MTM Risk Management Contracts	PLUS: MTM of Cash Flow and Fair Value Hedges	Total
Current Assets	$ 553	$ 1	$ 94	$ 648	$ 32	$ 680
Noncurrent Assets	260	1	115	376	2	378
Total Assets	813	2	209	1,024	34	1,058
Current Liabilities	(440)	-	(92)	(532)	(9)	(541)
Noncurrent Liabilities	(137)	-	(122)	(259)	(1)	(260)
Total Liabilities	(577)	-	(214)	(791)	(10)	(801)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 236	$ 2	$ (5)	$ 233	$ 24	$ 257

MTM Risk Management Contract Net Assets (Liabilities) Year Ended December 31, 2006 (in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2005	$ 215	$ -	$ (19)	$ 196
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(19)	-	13	(6)
Fair Value of New Contracts at Inception When Entered During the Period (a)	2	1	-	3
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	(2)	-	-	(2)
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	1	-	-	1
Changes in Fair Value due to Market Fluctuations During the Period (b)	24	1	1	26
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	15	-	-	15
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2006	$ 236	$ 2	$ (5)	233
Net Cash Flow and Fair Value Hedge Contracts				24
Ending Net Risk Management Assets at December 31, 2006				$ 257

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Change in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions. Approximately $7 million of the regulatory deferred change is due to the change in the SIA. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

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

The following table presents:

- The method of measuring 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, to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of December 31, 2006
(in millions)

	2007	2008	2009	2010	2011	After 2011	Total
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ (22)	$ 16	$ 2	$ -	$ -	$ -	$ (4)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	142	26	24	-	-	-	192
Prices Based on Models and Other Valuation Methods (b)	(7)	2	15	29	4	5	48
Total	$ 113	$ 44	$ 41	$ 29	$ 4	$ 5	$ 236
Generation and Marketing:							
Prices Actively Quoted – Exchange Traded Contracts	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prices Provided by Other External Sources – OTC Broker Quotes (a)	1	1	-	-	-	-	2
Prices Based on Models and Other Valuation Methods (b)	-	-	-	-	-	-	-
Total	$ 1	$ 1	$ -	$ -	$ -	$ -	$ 2
All Other:							
Prices Actively Quoted – Exchange Traded Contracts	$ 4	$ -	$ -	$ -	$ -	$ -	$ 4
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(2)	-	-	-	-	-	(2)
Prices Based on Models and Other Valuation Methods (b)	-	(1)	(4)	(3)	1	-	(7)
Total	$ 2	$ (1)	$ (4)	$ (3)	$ 1	$ -	$ (5)
Total:							
Prices Actively Quoted – Exchange Traded Contracts	$ (18)	$ 16	$ 2	$ -	$ -	$ -	$ -
Prices Provided by Other External Sources – OTC Broker Quotes (a)	141	27	24	-	-	-	192
Prices Based on Models and Other Valuation Methods (b)	(7)	1	11	26	5	5	41
Total	$ 116	$ 44	$ 37	$ 26	$ 5	$ 5	$ 233

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

(b) Prices Based on Models and Other Valuation Methods is in the absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity is limited, such valuations are classified as modeled.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

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

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of December 31, 2006

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	22
	Swaps	Northeast, Mid-Continent, Gulf Coast, Texas	22
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	AEP East - PJM	36
	Physical Forwards	AEP East	36
	Physical Forwards	AEP West	36
	Physical Forwards	West Coast	36
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	36
Coal	Physical Forwards	PRB, NYMEX, CSX	36

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

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

We use interest rate derivative transactions to manage interest rate risk related to existing variable rate debt and to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate exposure.

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2005 to December 31, 2006. The following table also indicates what portion of designated, effective hedges are expected to be reclassified into net income in the next 12-months. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2006
(in millions)

	Power	Interest Rate and Foreign Currency	Total
Beginning Balance in AOCI, December 31, 2005	$ (6)	$ (21)	$ (27)
Changes in Fair Value	17	(4)	13
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	6	2	8
Ending Balance in AOCI, December 31, 2006	$ 17	$ (23)	$ (6)
After Tax Portion Expected to be Reclassified to Earnings During Next 12-Months	$ 17	$ (2)	$ 15

Credit Risk

We limit credit risk in our marketing and trading activities by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. Only after an entity meets our internal credit rating criteria will we extend unsecured credit. We use Moody's Investors Service, Standard & Poor's and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. We use our analysis, in conjunction with the rating agencies' information, 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. As of December 31, 2006, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 3.02%, expressed in terms of net MTM assets and net receivables. As of December 31, 2006, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%
Investment Grade	$ 851	$ 116	$ 735	1	$ 99
Split Rating	39	14	25	1	25
Noninvestment Grade	17	12	5	2	4
No External Ratings:					
Internal Investment Grade	56	5	51	2	22
Internal Noninvestment Grade	35	14	21	3	19
Total as of December 31, 2006	$ 998	$ 161	$ 837	9	$ 169
Total as of December 31, 2005	$ 1,366	$ 484	$ 882	10	$ 322

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, 2009. This table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged" represents the portion of MWHs of future generation/production, taking into consideration scheduled plant outages, for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
December 31, 2006

	2007	2008	2009
Estimated Plant Output Hedged	91%	88%	89%

VaR Associated with Risk Management Contracts

Commodity Price Risk

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

VaR Model

December 31, 2006 (in millions)				December 31, 2005 (in millions)			
End	High	Average	Low	End	High	Average	Low
$3	$10	$3	$1	$3	$5	$3	$1

The High VaR for 2006 occurred in mid-August during a period of high gas and power volatility. The following day, positions were flattened and the VaR was significantly reduced.

Interest Rate Risk

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 $624 million at December 31, 2006 and $615 million at December 31, 2005. 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 financial position.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in common shareholders' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006. As discussed in Note 17 to the consolidated financial statements, the Company adopted FIN 47, "Accounting for Conditional Asset Retirement Obligations," effective December 31, 2005. As discussed in Note 9 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*, that American Electric Power Company, Inc. and subsidiary companies (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Company and our report dated February 28, 2007 expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph concerning the Company's adoption of new accounting pronouncements in 2004, 2005 and 2006.

Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

AEP management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2006. In making this assessment we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework*. Based on our assessment, the Company's internal control over financial reporting was effective as of December 31, 2006.

AEP's independent registered public accounting firm has issued an attestation report on our assessment of the Company's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in millions, except per-share and share amounts)

	2006	2005	2004
REVENUES			
Utility Operations	$ 12,066	$ 11,157	$ 10,620
Gas Operations	(85)	463	3,068
Other	641	491	557
TOTAL	12,622	12,111	14,245
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	3,817	3,592	3,059
Purchased Energy for Resale	856	687	670
Purchased Gas for Resale	-	256	2,807
Other Operation and Maintenance	3,639	3,619	3,676
Asset Impairments and Other Related Charges	209	39	-
(Gain) Loss on Disposition of Assets, Net	(69)	(120)	(4)
Depreciation and Amortization	1,467	1,348	1,324
Taxes Other Than Income Taxes	737	763	730
TOTAL	10,656	10,184	12,262
OPERATING INCOME	1,966	1,927	1,983
Interest and Investment Income	99	105	33
Carrying Costs Income	114	55	302
Allowance For Equity Funds Used During Construction	30	21	15
Investment Value Losses	-	(7)	(15)
Gain on Disposition of Equity Investments, Net	3	56	153
INTEREST AND OTHER CHARGES			
Interest Expense	732	697	781
Preferred Stock Dividend Requirements of Subsidiaries	3	7	6
TOTAL	735	704	787
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	1,477	1,453	1,684
Income Tax Expense	485	430	572
Minority Interest Expense	3	4	3
Equity Earnings of Unconsolidated Subsidiaries	3	10	18
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY LOSS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	992	1,029	1,127
DISCONTINUED OPERATIONS, NET OF TAX	10	27	83
EXTRAORDINARY LOSS, NET OF TAX	-	(225)	(121)
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	-	(17)	-
NET INCOME	$ 1,002	$ 814	$ 1,089
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	394,219,523	389,969,636	395,622,137
BASIC EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 2.52	$ 2.64	$ 2.85
Discontinued Operations, Net of Tax	0.02	0.07	0.21
Extraordinary Loss, Net of Tax	-	(0.58)	(0.31)
Cumulative Effect of Accounting Change, Net of Tax	-	(0.04)	-
TOTAL BASIC EARNINGS PER SHARE	$ 2.54	$ 2.09	$ 2.75
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	396,483,464	391,423,842	396,590,407
DILUTED EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 2.50	$ 2.63	$ 2.85
Discontinued Operations, Net of Tax	0.03	0.07	0.21
Extraordinary Loss, Net of Tax	-	(0.58)	(0.31)
Cumulative Effect of Accounting Change, Net of Tax	-	(0.04)	-
TOTAL DILUTED EARNINGS PER SHARE	$ 2.53	$ 2.08	$ 2.75
CASH DIVIDENDS PAID PER SHARE	$ 1.50	$ 1.42	$ 1.40

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2006 and 2005
(in millions)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 301	$ 401
Other Temporary Cash Investments	425	127
Accounts Receivable:		
Customers	676	826
Accrued Unbilled Revenues	350	374
Miscellaneous	44	51
Allowance for Uncollectible Accounts	(30)	(31)
Total Accounts Receivable	1,040	1,220
Fuel, Materials and Supplies	913	726
Risk Management Assets	680	926
Regulatory Asset for Under-Recovered Fuel Costs	38	197
Margin Deposits	120	221
Prepayments and Other	71	127
TOTAL	3,588	3,945
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,787	16,506
Transmission	7,018	6,433
Distribution	11,338	10,702
Other (including coal mining and nuclear fuel)	3,405	3,263
Construction Work in Progress	3,473	2,217
Total	42,021	39,121
Accumulated Depreciation and Amortization	15,240	14,837
TOTAL - NET	26,781	24,284
OTHER NONCURRENT ASSETS		
Regulatory Assets	2,477	3,262
Securitized Transition Assets	2,158	593
Spent Nuclear Fuel and Decommissioning Trusts	1,248	1,134
Goodwill	76	76
Long-term Risk Management Assets	378	886
Employee Benefits and Pension Assets	327	1,105
Deferred Charges and Other	910	843
TOTAL	7,574	7,899
Assets Held for Sale	44	44
TOTAL ASSETS	$ 37,987	$ 36,172

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2006 and 2005

	2006	2005
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$ 1,360	$ 1,144
Short-term Debt	18	10
Long-term Debt Due Within One Year	1,269	1,153
Risk Management Liabilities	541	906
Customer Deposits	339	571
Accrued Taxes	781	651
Accrued Interest	186	183
Other	962	842
TOTAL	5,456	5,460
NONCURRENT LIABILITIES		
Long-term Debt	12,429	11,073
Long-term Risk Management Liabilities	260	723
Deferred Income Taxes	4,690	4,810
Regulatory Liabilities and Deferred Investment Tax Credits	2,910	2,747
Asset Retirement Obligations	1,023	936
Employee Benefits and Pension Obligations	823	355
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	148	157
Deferred Credits and Other	775	762
TOTAL	23,058	21,563
TOTAL LIABILITIES	28,514	27,023
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		

	2006	2005
Shares Authorized	600,000,000	600,000,000
Shares Issued	418,174,728	415,218,830

	2006	2005
(21,499,992 shares were held in treasury at December 31, 2006 and 2005, respectively)	2,718	2,699
Paid-in Capital	4,221	4,131
Retained Earnings	2,696	2,285
Accumulated Other Comprehensive Income (Loss)	(223)	(27)
TOTAL	9,412	9,088
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 37,987	$ 36,172

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in millions)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 1,002	$ 814	$ 1,089
Less: Discontinued Operations, Net of Tax	(10)	(27)	(83)
Income Before Discontinued Operations	992	787	1,006
Adjustments for Noncash Items:			
Depreciation and Amortization	1,467	1,348	1,324
Deferred Income Taxes	24	65	291
Deferred Investment Tax Credits	(29)	(32)	(29)
Cumulative Effect of Accounting Changes, Net	-	17	-
Extraordinary Loss	-	225	121
Asset Impairments, Investment Value Losses and Other Related Charges	209	46	15
Carrying Costs Income	(114)	(55)	(302)
Gain on Sales of Assets and Equity Investments, Net	(72)	(176)	(157)
Amortization of Nuclear Fuel	50	56	52
Mark-to-Market of Risk Management Contracts	(37)	84	14
Pension Contributions to Qualified Plan Trusts	-	(626)	(231)
Fuel Over/Under-Recovery, Net	182	(239)	96
Deferred Property Taxes	(14)	(17)	(3)
Change in Other Noncurrent Assets	(15)	(115)	(176)
Change in Other Noncurrent Liabilities	28	67	260
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	177	(7)	280
Fuel, Materials and Supplies	(187)	(20)	33
Margin Deposits	101	(108)	6
Accounts Payable	56	140	(306)
Accrued Taxes	128	48	427
Customer Deposits	(232)	157	35
Other Current Assets	17	52	(53)
Other Current Liabilities	1	180	8
Net Cash Flows From Operating Activities	2,732	1,877	2,711
INVESTING ACTIVITIES			
Construction Expenditures	(3,528)	(2,404)	(1,637)
Change in Other Temporary Cash Investments, Net	(33)	76	32
Investment in Discontinued Operations, Net	-	-	(59)
Purchases of Investment Securities	(18,359)	(8,836)	(1,574)
Sales of Investment Securities	18,080	8,934	1,620
Acquisitions of Assets	-	(360)	-
Proceeds from Sales of Assets	186	1,606	1,357
Other	(89)	(21)	(68)
Net Cash Flows Used For Investing Activities	(3,743)	(1,005)	(329)
FINANCING ACTIVITIES			
Issuance of Common Stock	99	402	17
Repurchase of Common Stock	-	(427)	-
Change in Short-term Debt, Net	7	(13)	(409)
Issuance of Long-term Debt	3,359	2,651	682
Retirement of Long-term Debt	(1,946)	(2,729)	(2,511)
Dividends Paid on Common Stock	(591)	(553)	(555)
Other	(17)	(122)	(64)
Net Cash Flows From (Used For) Financing Activities	911	(791)	(2,840)
Net Increase (Decrease) in Cash and Cash Equivalents	(100)	81	(458)
Cash and Cash Equivalents at Beginning of Period	401	320	778
Cash and Cash Equivalents at End of Period	$ 301	$ 401	$ 320
CASH FLOWS FROM DISCONTINUED OPERATIONS			
Operating Activities	$ -	$ -	$ (3)
Investing Activities	-	-	(10)
Financing Activities	-	-	-
Net Decrease in Cash and Cash Equivalents from Discontinued Operations	-	-	(13)
Cash and Cash Equivalents from Discontinued Operations – Beginning of Period	-	-	13
Cash and Cash Equivalents from Discontinued Operations – End of Period	$ -	$ -	$ -

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005, and 2004
(in millions)

	Common Stock					
	Shares	**Amount**	**Paid-in Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Total**
DECEMBER 31, 2003	404	$ 2,626	$ 4,184	$ 1,490	$ (426)	$ 7,874
Issuance of Common Stock	1	6	11			17
Common Stock Dividends				(555)		(555)
Other			8			8
TOTAL						7,344
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(104)	(104)
Cash Flow Hedges, Net of Tax of $51					94	94
Minimum Pension Liability, Net of Tax of $52					92	92
NET INCOME				1,089		1,089
TOTAL COMPREHENSIVE INCOME						1,171
DECEMBER 31, 2004	405	2,632	4,203	2,024	(344)	8,515
Issuance of Common Stock	10	67	335			402
Common Stock Dividends				(553)		(553)
Repurchase of Common Stock			(427)			(427)
Other			20			20
TOTAL						7,957
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(6)	(6)
Cash Flow Hedges, Net of Tax of $15					(27)	(27)
Securities Available for Sale, Net of Tax of $11					20	20
Minimum Pension Liability, Net of Tax of $175					330	330
NET INCOME				814		814
TOTAL COMPREHENSIVE INCOME						1,131
DECEMBER 31, 2005	415	2,699	4,131	2,285	(27)	9,088
Issuance of Common Stock	3	19	80			99
Common Stock Dividends				(591)		(591)
Other			10			10
TOTAL						8,606
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Cash Flow Hedges, Net of Tax of $11					21	21
Securities Available for Sale, Net of Tax of $0					(1)	(1)
Minimum Pension Liability, Net of Tax of $1					2	2
NET INCOME				1,002		1,002
TOTAL COMPREHENSIVE INCOME						1,024
Minimum Pension Liability Elimination, Net of Tax of $9					17	17
SFAS 158 Adoption, Net of Tax of $126					(235)	(235)
DECEMBER 31, 2006	418	$ 2,718	$ 4,221	$ 2,696	$ (223)	$ 9,412

See Notes to Consolidated Financial Statements.

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by nine of our electric utility operating companies is the generation, transmission and distribution of electric power. TCC and TNC are completing the final stage of exiting the generation business. WPCo and KGPCo provide only transmission and distribution services. AEGCo is a regulated electricity generation business whose function is to provide power to our regulated electric utility operating companies. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005. These companies maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our operations include nonregulated independent power and cogeneration facilities, coal mining and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP, AEPSC and its other subsidiaries are regulated by the FERC under the 2005 Public Utility Holding Company Act (2005 PUHCA). AEP's public utility subsidiaries are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The state regulatory commissions with jurisdiction approve the rates charged and regulate the services and operations of the utility subsidiaries for the generation and supply of power, a majority of transmission energy delivery services and distribution services. The FERC also regulates certain, mostly affiliated, transactions under the 2005 PUHCA.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based and are not cost-based regulated unless we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region in which the transaction is taking place. We have wholesale power supply contracts with various municipalities and cooperatives that are FERC regulated, cost-based contracts and our wholesale power transactions in the SPP region are all cost-based due to our having market power in the SPP region as determined by the FERC. As of December 31, 2006, only SWEPCo, PSO and TNC operate in the SPP region.

The FERC also regulates, on a cost basis, our wholesale transmission service and rates except in Texas. The FERC has claimed jurisdiction over retail transmission rates when the retail rates are unbundled in connection with restructuring. In Ohio, CSPCo's and OPCo's rates are unbundled, therefore our retail transmission rates are based on FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Although our retail rates are unbundled in Virginia and Texas, retail transmission rates are still regulated, on a cost basis, by the state regulatory commissions.

In addition, FERC regulates our East and West Power Pools, East Transmission Equalization Agreement, System Interim Allowance Agreement, and SIA, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to the agreements.

The state regulatory commissions regulate all of our retail public utility operations (generation, transmission and distribution operations) and rates except in states that have enacted restructuring legislation where only transmission and distribution rates are regulated on a cost-basis and unbundled by function. Our retail generation/power supply operations and rates are cost-based regulated by the state regulatory commissions except for CSPCo and OPCo in Ohio and APCo in Virginia, which are in transition to market pricing under state restructuring legislation. However, Virginia legislature adopted amendments to its electric restructuring law. If approved, Virginia would return to a form of cost-based regulation. AEP has no Texas jurisdictional retail generation/power supply operations in Texas other than a minor generational supply operation through a commercial and industrial customer REP. See Note 4 for further details of such legislation and its effects on AEP in Ohio, Texas, Virginia and Michigan.

In 2004 and 2005, we were subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (1935 PUHCA). The Energy Policy Act of 2005 repealed the 1935 PUHCA effective February 8, 2006 and replaced it with the 2005 PUHCA. With the repeal of the 1935 PUHCA, the SEC no longer has jurisdiction over the activities of registered holding companies, their respective service corporations and their intercompany transactions, which it regulated predominantly at cost. Jurisdiction over holding company-related activities has been transferred to the FERC. Regulation and required reporting under the 2005 PUHCA have been reduced compared to the 1935 PUHCA. However, the FERC has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets, mergers with another electric utility or holding company, intercompany transactions, accounting and AEPSC intercompany service billings which are generally at cost. The intercompany sale of non-power goods and non-AEPSC services to affiliates cannot exceed market under the 2005 PUHCA. The state regulatory commissions in Virginia and West Virginia also regulate certain intercompany transactions under their affiliates statutes.

Both FERC and state regulatory commissions are permitted to review and audit the books and records of any company within a public utility holding company system.

Principles of Consolidation

Our consolidated financial statements include AEP and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries or substantially-controlled variable interest entities (VIE). Intercompany items are eliminated in consolidation. Equity investments not substantially-controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Income. We also consolidate VIEs in accordance with FASB Interpretation Number (FIN) 46 (revised December 2003) “Consolidation of Variable Interest Entities” (FIN 46R) (see “Guarantees of Third-Party Obligations” section of Note 6). We also have generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on our Consolidated Statements of Income and our proportionate share of the assets and liabilities are reflected on our Consolidated Balance Sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of cost-based rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the commencement of legislatively required transitions to customer choice and market-based rates, we discontinued the application of SFAS 71, regulatory accounting, for the generation portion of our business: in Ohio for OPCo and CSPCo in September 2000, in Virginia for APCo in June 2000 and in Texas for TCC, TNC and the Texas portion of SWEPCo in September 1999. SFAS 101, “Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71” requires the recognition of an impairment of stranded regulatory assets and stranded plant costs if they are not recoverable in regulated rates. Such impairments arising from the discontinuance of SFAS 71 are classified as an extraordinary item. TCC recorded extraordinary impairment losses related to its regulatory assets and plant costs in 2004 and 2005 resulting from the discontinuance of cost-based regulation of their generation business without full recovery of the resultant stranded costs.

Use of Estimates

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

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and other investments are stated at fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are charged to accumulated depreciation. For nonregulated operations, retirements from the plant accounts, net of salvage, are charged to accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Equity investments are required to be tested for impairment when it is determined there may be an other than temporary loss in value.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

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

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For nonregulated operations including domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs."

Valuation of Nonderivative Financial Instruments

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

Cash and Cash Equivalents

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

Other Temporary Cash Investments

Other Temporary Cash Investments include marketable securities that we intend to hold for less than one year and funds held by trustees primarily for the payment of debt.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS 115). We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Cash Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive income. Held-to-maturity securities reflected in Other Temporary Cash Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method. The fair value of most investment securities is determined by currently available market prices. Where quoted market prices are not available, we use the market price of similar types of securities that are traded in the market to estimate fair value.

The following is a summary of Other Temporary Cash Investments at December 31:

	2006				2005			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Other Temporary Cash Investments				(in millions)				
Cash (a)	$ 138	$ -	$ -	$ 138	$ 96	$ -	$ -	$ 96
Government Debt Securities	258	-	-	258	-	-	-	-
Corporate Equity Securities	1	28	-	29	2	29	-	31
Total Other Temporary Cash Investments	$ 397	$ 28	$ -	$ 425	$ 98	$ 29	$ -	$ 127

(a) Primarily represents amounts held for the payment of debt.

Proceeds from sales of current available-for-sale securities were $17,449 million, $8,228 million and $670 million in 2006, 2005 and 2004, respectively. Purchases of current available-for-sale securities were $17,667 million, $8,075 million and $573 million in 2006, 2005 and 2004, respectively. Gross realized gains from the sale of current available-for-sale securities were $39 million and $47 million in 2006 and 2005, respectively, and were not material in 2004. Gross realized losses from the sale of current available-for-sale securities were not material in 2006, 2005 or 2004.

The fair value of debt securities, summarized by contractual maturities, at December 31, 2006 is as follows:

Maturity	Fair Value of Debt Securities (in millions)
2007	$ -
2008 – 2011	-
2012 – 2016	4
After 2016	254
Total	$ 258

Inventory

Fossil fuel inventories are carried at average cost for AEGCo, APCo, I&M, KPCo and SWEPCo. OPCo and CSPCo value fossil fuel inventories at the lower of average cost or market. PSO carries fossil fuel inventories utilizing a LIFO method. TNC carries fossil fuel inventories at the lower of cost or market using a LIFO method. Materials and supplies inventories are carried at average cost.

Accounts Receivable

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

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

AEP Credit factors accounts receivable for certain subsidiaries, including CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be removed from the company's balance sheet (see "Sale of Receivables – AEP Credit" section of Note 15).

Foreign Currency Translation

The financial statements of subsidiaries outside the U.S. that are included in our consolidated financial statements and investments outside the U.S. that are accounted for under the equity method are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52, "Foreign Currency Translation." In 2006, we completed the disposal of our various non-U.S. equity method investments. Revenues and expenses are translated at monthly average foreign currency exchange rates throughout the year, unless a specific rate can be identified through an event. Assets and liabilities are translated into U.S. dollars at year-end foreign currency exchange rates. Accordingly, our consolidated common shareholders' equity will fluctuate depending on the relative strengthening or weakening of the U.S. dollar versus relevant foreign currencies. Currency translation gain and loss adjustments are recorded in shareholders' equity as Accumulated Other Comprehensive Income (Loss). The foreign currency translation balance of Accumulated Other Comprehensive Income (Loss) as of December 31, 2006 and 2005 was $58 thousand and $53 thousand, respectively, and was reduced primarily due to the disposition of our U.K. assets in 2004, which is reflected in Discontinued Operations on our Consolidated Statements of Income.

Deferred Fuel Costs

The cost of fuel and related chemical and emission allowance consumables are charged to Fuel and Other Consumables Used for Electric Generation Expense when the fuel is burned or the consumable is utilized. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. On a routine basis, state regulatory commissions audit our fuel cost calculations. When a fuel cost disallowance becomes probable, we adjust our deferrals and record provisions for estimated refunds to recognize these probable outcomes (see Note 4). Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated as in West Virginia (prior to July 2006) and Texas-ERCOT, respectively.

In general, changes in fuel costs in Kentucky for KPCo, Michigan for I&M, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO, Virginia and West Virginia (beginning July 1, 2006) for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All or a portion of profits from off-system sales are shared with customers through fuel clauses in Texas (SPP area only), Oklahoma, Louisiana, Arkansas, Kentucky, West Virginia (beginning July 1, 2006) and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002), changes in fuel costs impact earnings unless recovered in the sales price for electricity. In other state jurisdictions, (Indiana and prior to July 1, 2006 in West Virginia), where fuel clauses have been capped, frozen or suspended for a period of years, fuel costs impact earnings. The Indiana fuel clause suspension ends June 30, 2007. In West Virginia, deferred fuel accounting for over- or under-recovery began July 1, 2006. Changes in fuel costs also impact earnings for certain of our IPP generating units that do not have long-term contracts for their fuel supply or have not hedged fuel costs.

Revenue Recognition

Regulatory Accounting

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

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

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. We recognize the revenues on our Consolidated Statements of Income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue. In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase-and-sale contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio, Virginia and the ERCOT portion of Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

For power purchased under derivative contracts in our west zone where we are short capacity, prior to settlement, we recognize as Revenues the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period. If the contract results in the physical delivery of power, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts gross as Purchased Energy for Resale. If the contract does not physically deliver, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts as Revenues on our Consolidated Statements of Income on a net basis (see “Derivatives and Hedging” section of Note 12).

Domestic Gas Pipeline and Storage Activities

As a result of the sale of HPL in 2005, our domestic gas pipeline and storage activities ceased. Prior to the sale of HPL, we recognized revenues from domestic gas pipeline and storage services when gas was delivered to contractual meter points or when services were provided, with the exception of certain physical forward gas purchase-and-sale contracts that were derivatives and accounted for using MTM accounting (resale gas contracts). The unrealized and realized gains and losses on resale gas contracts for the sale of natural gas are presented as Revenues on our Consolidated Statements of Income. The unrealized and realized gains and losses on physically-settled resale gas contracts for the purchase of natural gas are presented as Purchased Gas for Resale on our Consolidated Statements of Income (see “Fair Value Hedging Strategies” section of Note 12).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where we own assets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts, which include exchange traded futures and options and over-the-counter options and swaps.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow or fair value hedge relationship, or as a normal purchase or sale. We include the unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on our Consolidated Statements of Income on a net basis. In jurisdictions subject to cost-based regulation, we defer the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on our Consolidated Balance Sheets as Risk Management Assets or Liabilities as appropriate.

Certain wholesale marketing and risk management transactions are designated as hedges of future cash flows as a result of forecasted transactions (cash flow hedge) or as hedges of a recognized asset, liability or firm commitment (fair value hedge). We recognize the gains or losses on derivatives designated as fair value hedges in Revenues on our Consolidated Statements of Income in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, we initially record the effective portion of the derivative's gain or loss as a component of Accumulated Other Comprehensive Income (Loss) and, depending upon the specific nature of the risk being hedged, subsequently reclassify into Revenues or fuel expenses on our Consolidated Statements of Income when the forecasted transaction is realized and affects earnings. We recognize the ineffective portion of the gain or loss in Revenues on our Consolidated Statements of Income immediately, except in those jurisdictions subject to cost-based regulation. In those regulated jurisdictions we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains) (see "Fair Value Hedging Strategies" and "Cash Flow Hedging Strategies" sections of Note 12).

Barging Activities

MEMCO Operations revenue is recognized based on percentage of completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by MEMCO's computerized barge tracking system. The recognition of revenue based upon the percentage of voyage completion results in a better matching of revenue and expenses.

Construction Projects for Outside Parties

We engage in construction projects for outside parties and account for the projects on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as we incur and bill project costs to the outside party.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. We defer maintenance costs during refueling outages at the Cook Plant and amortize the costs over the period between outages in accordance with rate orders in Indiana and Michigan.

Income Taxes and Investment Tax Credits

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

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

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

Excise Taxes

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

Debt and Preferred Stock

We defer gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on our Consolidated Statements of Income.

We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the amortization expense in Interest Expense on our Consolidated Statements of Income.

Where reflected in rates, we include redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries in paid-in capital and amortize the premiums to retained earnings commensurate with recovery in rates. We credit the excess of par value over costs of preferred stock reacquired to paid-in capital and reclassify the excess to retained earnings upon the redemption of the entire preferred stock series. We credit the excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries to retained earnings upon reacquisition.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize purchased goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives, currently ranging from 5 to 10 years, to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Emission Allowances

We record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. We follow the inventory model for all allowances. We record allowances expected to be consumed within one year in Fuel, Materials and Supplies and allowances with expected consumption beyond one year in Other Noncurrent Assets-Other on our Consolidated Balance Sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income at an average cost. We record allowances held for speculation in Other Current Assets on our Consolidated Balance Sheets. We report the purchases and sales of allowances in the Operating Activities section of the Statements of Cash Flows. We record the net margin on sales of emission allowances in Utility Operations Revenue on our Consolidated Statements of Income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of the applicable company or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

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

We record securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at market value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Upon the issuance of FSP 115-1 and 124-1 "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments," we consider all nuclear decommissioning trust fund and spent nuclear fuel trust fund investments in unrealized loss positions to be other-than-temporary impairments as we do not make specific investment decisions regarding assets held in trusts. Thus, effective in 2006, the other-than-temporary impairments are considered realized losses and will reduce the cost basis of the securities which will affect any future unrealized gain or realized gains or losses. Amounts prior to 2006 were not restated as the other-than-temporary impairments do not affect earnings or AOCI. We record unrealized gains and losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. See Note 10 for additional discussion of nuclear matters.

Comprehensive Income (Loss)

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

Components of Accumulated Other Comprehensive Income (Loss)

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

	December 31,	
	2006	**2005**
Components	**(in millions)**	
Securities Available for Sale, Net of Tax	$ 18	$ 19
Cash Flow Hedges, Net of Tax	(6)	(27)
Minimum Pension Liability, Net of Tax (a)	-	(19)
SFAS 158 Adoption, Net of Tax (a)	(235)	-
Total	$ (223)	$ (27)

(a) See "SFAS 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" section of Note 2.

At December 31, 2006, we expect to reclassify approximately $15 million of net gains 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. The actual amounts that are reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ as a result of market fluctuations.

At December 31, 2006, forty-two-months is the maximum length of time that our exposure to variability in future cash flows is hedged with contracts designated as cash flow hedges.

Stock-Based Compensation Plans

As of December 31, 2006, we had stock options, performance units, restricted shares and restricted stock units outstanding to employees under The Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was originally approved by shareholder vote in 2000 and the Amended and Restated version was subsequently approved in 2005.

We maintain career share accounts under the Stock Ownership Requirement Plan to facilitate executives in meeting minimum stock ownership requirements assigned to executives by the HR Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends.

We also compensate our non-employee directors, in part, with stock units under The Stock Unit Accumulation Plan for Non-Employee Directors. These stock units also do not become payable in cash to Directors until after their service to the company ends.

In addition, we maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP stock.

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), “Share-Based Payment,” (SFAS 123R) which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors including stock options and employee stock purchases based on estimated fair values. See the SFAS 123 (revised 2004) “Share-Based Payment (SFAS 123R)” section of Note 2 for additional discussion.

In conjunction with the adoption of SFAS 123R, we changed our method of attributing the value of stock-based compensation to expense for awards with service only conditions from the accelerated multiple-option approach to the straight-line single-option method. We recognize compensation expense for all share-based payment awards granted prior to January 1, 2006 using the accelerated multiple-option approach while we recognize compensation expense for all share-based payment awards with service only condition granted on or after January 1, 2006 using the straight-line single-option method. In 2006, we granted an award with performance conditions which continue to be expensed on the accelerated multiple-option approach. As stock-based compensation expense recognized on our Consolidated Statements of Income for the year ended December 31, 2006 is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures. SFAS 123R requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. In our pro forma information presented in Note 16 as required under SFAS 123 for the periods prior to 2006, we accounted for forfeitures as they occurred.

For the years ended December 31, 2005 and 2004, no stock option expense was reflected in Net Income as we accounted for stock options using the intrinsic value method under Accounting Principles Board (APB) Opinion No. 25, “Accounting For Stock Issued to Employees.” Under the intrinsic value method, no stock option expense is recognized when the exercise price of the stock options granted equals the fair value of the underlying stock at the date of grant. For the years ended December 31, 2006, 2005 and 2004, compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director’s stock units. See Note 16 for additional discussion.

Pro Forma Information Under SFAS 123, "Accounting for Stock-Based Compensation," for Periods Presented Prior to January 1, 2006

The following table shows the effect on our Net Income and Earnings Per Share as if we had applied fair value measurement and recognition provisions of SFAS 123 to stock-based employee and director compensation awards for the years ended December 31, 2005 and 2004:

	2005	2004
	(in millions, except per share data)	
Net Income, as reported	$ 814	$ 1,089
Add: Stock-based compensation expense included in reported Net Income, net of related tax effects	22	15
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	(22)	(18)
Pro Forma Net Income	$ 814	$ 1,086
Earnings Per Share		
Basic – as Reported	$ 2.09	$ 2.75
Basic – Pro Forma (a)	$ 2.09	$ 2.74
Diluted – as Reported	$ 2.08	$ 2.75
Diluted – Pro Forma (a)	$ 2.08	$ 2.74

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

Earnings Per Share (EPS)

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on our Consolidated Statements of Income:

	2006		2005		2004	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Applicable to Common Stock	$ 1,002		$ 814		$ 1,089	
Average Number of Basic Shares Outstanding	394.2	$ 2.54	390.0	$ 2.09	395.6	$ 2.75
Average Dilutive Effect of:						
Performance Share Units	1.8	0.01	1.0	0.01	0.6	-
Stock Options	0.3	-	0.3	-	0.3	-
Restricted Stock Units	0.1	-	-	-	-	-
Restricted Shares	0.1	-	0.1	-	0.1	-
Average Number of Diluted Shares Outstanding	396.5	$ 2.53	391.4	$ 2.08	396.6	$ 2.75

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share.

Options to purchase 0.4 million, 0.5 million and 5.2 million shares of common stock were outstanding at December 31, 2006, 2005 and 2004, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the year-end market price of the common shares and, therefore, the effect would be antidilutive.

Supplementary Information

Related Party Transactions	2006	2005	2004
		(in millions)	
AEP Consolidated Purchased Energy:			
Ohio Valley Electric Corporation (43.47% Owned)	$ 223	$ 196	$ 161
Sweeny Cogeneration Limited Partnership (50% Owned)	121	141	-
AEP Consolidated Other Revenues – Barging and Other Transportation Services – Ohio Valley Electric Corporation (43.47% Owned)	28	20	14
AEP Consolidated Revenues – Utility Operations:			
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% Owned)	(37)	-	-
Cash Flow Information			
Cash paid (received) for:			
Interest, Net of Capitalized Amounts	664	637	755
Income Taxes, Net of Refunds	358	439	(107)
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	106	63	123
Disposition of Liabilities Related to Acquisitions/Divestitures, Net	-	(18)	(67)
Noncash Construction Expenditures Included in Accounts Payable at December 31	404	253	116
Noncash Acquisition of Nuclear Fuel in Accounts Payable at December 31	-	24	-

Year Ended December 31 applies to the columns above.

Power Projects

We own a 50% interest in Sweeny, a domestic unregulated power plant with a capacity of 480 MW located in Texas. In 2006, we sold our 50% interest in an international power plant totaling 600 MW located in Mexico (see "Dispositions" section of Note 8).

We account for investments in power projects that are 50% or less owned using the equity method and report them as Deferred Charges and Other on our Consolidated Balance Sheets. At December 31, 2006 and 2005, the 50% owned domestic power project and international power investment are accounted for under the equity method and have unrelated third-party partners. The domestic project is a combined cycle gas turbine that provides steam to a host commercial customer and is considered a Qualifying Facility (QF) under PURPA. The international power investment was classified as a Foreign Utility Company (FUCO) under the Energy Policies Act of 1992.

The domestic power project has project-level financing, which is nonrecourse to AEP.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation.

On our Consolidated Balance Sheets, we reclassified $147 million of mining equipment as of December 31, 2005 from Production to Other within Property, Plant and Equipment.

On our Consolidated Statements of Income, we reclassified regulatory credits related to regulatory asset cost deferral on ARO from Depreciation and Amortization to Other Operation and Maintenance to offset the ARO accretion expense. These reclassifications totaled $30 million and $24 million for 2005 and 2004, respectively.

In our segment information, we reclassified two subsidiary companies, AEP Texas Commercial & Industrial Retail GP, LLC and AEP Texas Commercial & Industrial Retail LP, from the Utility Operations segment to the Generation and Marketing segment as discussed in Note 11. Combined revenues for these companies totaled $36 million and $44 million for 2005 and 2004, respectively. As a result, on our Consolidated Statements of Income we reclassified these revenues from Utility Operations to Other.

These revisions had no impact on our previously reported results of operations, cash flows or changes in shareholders' equity.

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

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we thoroughly review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of final pronouncements that we have determined relate to our operations.

SFAS 123 (revised 2004) "Share-Based Payment" (SFAS 123R)

The FASB issued SFAS 123R, requiring entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting.

In 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued FASB Staff Positions (FSP) that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R in 2006. We adopted SFAS 123R using the modified prospective method without materially affecting our results of operations, cash flows or financial condition.

SFAS 154 "Accounting Changes and Error Corrections" (SFAS 154)

In 2005, the FASB issued SFAS 154. The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that do not specify transition requirements. It requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. It also requires that retrospective application of a change in accounting principle should be recognized in the period of the accounting change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 was effective for accounting changes and corrections of errors after January 1, 2006 and is applied as necessary.

SFAS 157 "Fair Value Measurements" (SFAS 157)

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level and an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption.

SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. We expect that the adoption of this standard will impact MTM valuations of certain contracts, but we are unable to quantify the effect. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. We will adopt SFAS 157 effective January 1, 2008.

SFAS 158 "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"

In September 2006, the FASB issued SFAS 158, amending previous standards. It requires employers to fully recognize the obligations associated with defined benefit pension plans and other postretirement employee benefit (OPEB) plans, which include retiree healthcare, in their balance sheets. Previous standards required an employer to disclose the complete funded status of its plan only in the notes to the financial statements and provided that an employer delay recognition of certain changes in plan assets and obligations that affected the costs of providing benefits resulting in an asset or liability that often differed from the plan's funded status. SFAS 158 requires a defined benefit pension or postretirement plan sponsor (a) recognize in its statement of financial position an asset for a plan's overfunded status or a liability for the plan's underfunded status, (b) measure the plan's assets and obligations that determine its funded status as of the end of the employer's fiscal year (with limited exceptions), and (c) recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year but are not recognized as a component of net periodic benefit cost pursuant to previous standards. It also requires an employer to disclose additional information on how delayed recognition of certain changes in the funded status of a defined benefit pension or OPEB plan affects net periodic benefit costs for the next fiscal year.

The effect of SFAS 158 is to adjust pretax AOCI at the end of each year, for both underfunded deferred benefit and overfunded pension and OPEB plans, to an amount equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating investment returns and discount rates. Favorable changes include higher returns that increase plan assets and higher discount rates that reduce the discounted benefit obligation.

We adopted SFAS 158 as of December 31, 2006. We recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of our regulated operations that for ratemaking purposes will be deferred for future recovery. The following table shows the incremental effect of this standard on our financial statements versus prior accounting requirements including the additional minimum pension liability provisions of SFAS 87, "Employers' Accounting for Pensions," which were replaced by SFAS 158 as follows:

	Before Application of SFAS 158	**Incremental Effect**	**After Application of SFAS 158**
		(in millions)	
Prepaid Benefit Costs	$ 1,038	$ (718)	$ 320
Current Accrued Benefit Liability	-	(13)	(13)
Noncurrent Accrued Benefit Liability	(80)	(505)	(585)
Regulatory Assets	-	875	875
Deferred Income Taxes	9	117	126
Additional Minimum Liability	(32)	32	N/A
Intangible Asset	6	(6)	N/A
Net of Tax AOCI Equity Reduction	17	218	235
Total	$ 958	$ -	$ 958

N/A = Not Applicable

SFAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS 159)

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities.

SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. In the event we elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. We will adopt SFAS 159 effective January 1, 2008.

FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" (FIN 48)

In July 2006, the FASB issued FIN 48. It clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. FIN 48 is effective for fiscal years beginning after December 15, 2006. Although we are in the process of evaluating the impact of FIN 48, we estimate the effect of this interpretation on our financial statements to be an unfavorable adjustment to retained earnings of less than $15 million.

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

This issue focuses on two inventory exchange issues. Purchases or sales of inventory transactions with the same counterparty should be combined under APB Opinion No. 29, "Accounting for Nonmonetary Transactions," if they were entered in contemplation of one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value if an entity exchanges finished goods for raw materials or work in progress within the same line of business and if fair value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within the same line of business should be valued at the carrying amount of the inventory transferred. We implemented this issue beginning April 1, 2006 without a material impact on our financial statements.

EITF Issue 06-3 "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)" (EITF 06-3)

In June 2006, the EITF reached a consensus on the income statement presentation of various types of taxes. The scope of this issue includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to, sales, use, value added, and some excise taxes. The presentation of taxes within the scope of this issue on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed. The EITF's decision on gross/net presentation requires that any such taxes reported on a gross basis be disclosed on an aggregate basis in interim and annual financial statements, for each period for which an income statement is presented, if those amounts are significant.

As disclosed in Note 1, we act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. Our policy is to present these taxes on a net basis. We do not recognize these taxes as revenues or expenses. Therefore, this issue did not impact our financial statements.

SAB No. 108 "Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in the Current Year Financial Statements" (SAB 108)

In September 2006, the SEC staff issued SAB 108 addressing diversity in practice when quantifying the effect of an error on financial statements. It provides guidance on the consideration of the effects of prior year misstatements in quantifying misstatements in current year financial statements. Our adoption of SAB 108, effective December 31, 2006, did not have a material impact on our financial statements.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including business combinations, revenue recognition, liabilities and equity, derivatives disclosures, earnings per share calculations, leases, insurance, subsequent events and related tax impacts. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

EXTRAORDINARY ITEMS

Results for 2005 reflect net adjustments made by TCC to its net true-up regulatory asset for the PUCT's final order in its True-up Proceeding issued in February 2006. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million ($225 million, net of tax) was recorded as an extraordinary item in accordance with SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" (SFAS 101) and is reflected in Extraordinary Loss, Net of Tax on our 2005 Consolidated Statement of Income (see " TCC Texas Restructuring" section of Note 4).

In 2004, as part of its True-up Proceeding, TCC made net adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset related to its transition to retail competition. We recorded this adjustment as an extraordinary item in accordance with SFAS 101. The adjustment is included in Extraordinary Loss, Net of Tax on our 2004 Consolidated Statement of Income.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Asset Retirement Obligations

In 2005, we recorded a $26 million ($17 million, net of tax) cumulative effect of accounting change for ARO in accordance with FIN 47 in the Utility Operations segment. This adjustment is included in Cumulative Effect of Accounting Change, Net on our 2005 Consolidated Statement of Income.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2006 and 2005 by operating segment are as follows:

	Utility Operations	MEMCO Operations	AEP Consolidated
		(in millions)	
Balance at January 1, 2005	$ 37.1	$ 38.8	$ 75.9
Impairment Losses	-	-	-
Balance at December 31, 2005	37.1	38.8	75.9
Impairment Losses	-	-	-
Balance at December 31, 2006	$ 37.1	$ 38.8	$ 75.9

In the fourth quarters of 2005 and 2006, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses required.

Other Intangible Assets

Acquired intangible assets subject to amortization were $19.4 million at December 31, 2006 and $23.9 million at December 31, 2005, net of accumulated amortization and are included in Deferred Charges and Other on our Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31, 2006		December 31, 2005	
	Amortization Life	**Gross Carrying Amount**	**Accumulated Amortization**	**Gross Carrying Amount**	**Accumulated Amortization**
	(in years)	**(in millions)**		**(in millions)**	
Patent	5	$ 0.1	$ 0.1	$ 0.1	$ 0.1
Easements	10	2.2	1.1	2.2	0.7
Purchased Technology	10	10.9	5.4	10.9	4.3
Advanced Royalties	10	29.4	16.6	29.4	13.6
Total		$ 42.6	$ 23.2	$ 42.6	$ 18.7

Amortization of intangible assets was $5 million, $4 million and $4 million for 2006, 2005 and 2004, respectively. Our estimated total amortization is $5 million for 2007, $4 million per year for 2008 through 2010 and $2 million in 2011, when all assets will be fully amortized with no residual value.

Other than goodwill, we have no intangible assets that are not subject to amortization.

4. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and state commissions. This note is a discussion of pending rate matters, including industry restructuring and customer choice related proceedings, that could materially impact results of operations and cash flows.

Ohio Rate Matters

Ohio Restructuring and Rate Stabilization Plans

Ohio restructuring legislation provided for a transition to market pricing for power supply beginning on January 1, 2006. Open access to power suppliers began in Ohio on January 1, 2001 with a five-year transition to market pricing. Under a 2000 PUCO-approved settlement agreement, CSPCo and OPCo (the Ohio companies) froze their rates through December 31, 2005. In accordance with the approved settlement agreement, CSPCo and OPCo amortize their stranded generation-related transition regulatory assets commensurate with recovery through their frozen rates and starting January 1, 2006 through rate riders that expire in 2008 and 2007, respectively. To date, CSPCo and OPCo have lost very few customers to competing suppliers.

In 2005, the PUCO approved Rate Stabilization Plans (RSPs) for the Ohio companies effective January 1, 2006 and ending December 31, 2008, which allow the Ohio companies to increase their generation rates over three years. The approved three-year RSPs provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7% a year, respectively, and provide for possible additional annual generation rate increases of up to an average of 4% per year to recover governmentally-mandated costs. During 2006 through 2008, the RSPs also allow the Ohio companies to recover regulatory assets for 2004 and 2005 environmental carrying costs and PJM-related administrative costs and congestion costs, net of financial transmission rights (FTR) revenues, related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program.

Pretax earnings increased by $110 million for the Ohio companies in 2006 from the RSP rate increases, net of the amortization of RSP regulatory assets. This increase includes the recovery of unrecognized equity carrying costs for 2004 and 2005. At December 31, 2006, unrecognized equity costs total $29 million. As of December 31, 2006, the unamortized RSP regulatory assets to be recovered through December 31, 2008 were $38 million.

In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court challenging the RSPs and also arguing that there is no POLR obligation the Ohio companies are entitled to recover. In July 2006, the Ohio Supreme Court vacated the PUCO's RSP order for the Ohio companies and remanded the case to the PUCO for further proceedings. In August 2006, the PUCO acted on the Ohio companies' remand case ordering them to file a plan to provide an option for customer participation in the electric market through competitive bids or other reasonable means and also held that the RSP shall remain effective. Accordingly, the Ohio companies continue collecting RSP revenues, amortizing the RSP costs and realizing and recognizing related equity carrying costs.

In September 2006, the Ohio companies submitted their proposal to the PUCO to provide additional options for customer participation in the electric market. The proposal provides for the recovery of the cost of providing the additional options. In January 2007, the PUCO set a schedule for interested persons to file comments concerning the proposal.

The Ohio Supreme Court did not address any other issues raised on appeal, stating its decision did not preclude the Ohio Consumers' Counsel from raising those issues in a future appeal. Management believes that the RSP regulatory assets remain probable of recovery and that the Ohio companies will continue to collect RSP revenues.

In January 2007, CSPCo and OPCo filed with the PUCO under the 4% provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover governmentally-mandated costs.

CSPCo and OPCo have been involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the rate stabilization plans. At this time, management is unable to predict whether the Ohio companies will transition to market pricing, whether the RSP will be extended with or without modification, or whether cost-based regulation will be reinstated on January 1, 2009 when the RSP period ends.

Customer Choice Deferrals

As provided in the restructuring settlement agreement approved by the PUCO in 2000, the Ohio companies established regulatory assets for customer choice implementation costs and related carrying costs in excess of $40 million in total for recovery in the next general rate filing to change distribution rates after December 31, 2007 for OPCo and December 31, 2008 for CSPCo. Pursuant to the RSPs, recovery of these amounts for OPCo was further deferred until the next distribution rate filing to change rates after the end of the RSP period dated December 31, 2008. Through December 31, 2006, we incurred $99 million of such costs and established regulatory assets of $49 million for such costs. We have not recognized $10 million of equity carrying costs, which are not recognizable until collected. We believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and should be recoverable in future distribution rates.

IGCC Plant

In March 2005, the Ohio companies filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery, or refund, in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected $1.2 billion cost of the plant along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the 4% limit on additional generation rate increases the Ohio companies could request under their RSPs.

In April 2006, the PUCO issued an order authorizing the Ohio companies to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over no more than a twelve-month period effective July 1, 2006. Through December 31, 2006, the Ohio companies recorded pre-construction IGCC regulatory assets of $20 million and recovered $12 million of those costs. We are currently recovering the remaining amounts through June 30, 2007. In its June order, the PUCO indicated that if the

Ohio companies have not commenced continuous construction of the IGCC plant within five years of the order, all charges collected for pre-construction costs, which are assignable to other jurisdictions, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. No date for a further hearing has been set.

In August 2006, The Industrial Energy Users, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. The Ohio companies believe that the PUCO's authorization to begin collection of Phase 1 rates is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, the Ohio companies could be required to refund Phase I cost-related recoveries.

Transmission Rate Filing

In accordance with the RSPs, in December 2005, the PUCO approved the recovery of certain RTO transmission costs through separate transmission cost recovery riders for the Ohio companies. The transmission cost recovery riders are subject to an annual true-up process. In May 2006, the PUCO issued an order approving a two-step increase in the transmission cost recovery riders effective April 1, 2006. The Ohio companies implemented the new tariffs in June 2006. They reflect the Ohio companies' share of the loss of SECA revenues in step one. The step two increase, effective August 1, 2006, reflects the change in the AEP East Zone transmission rate approved by the FERC related to completion of the new Wyoming-Jacksons Ferry 765 kV line.

In October 2006, the Ohio companies filed for initial true-ups under the transmission cost recovery riders. The filings reflect the refund of a regulatory liability, as of September 30, 2006, of $12 million and $16 million for CSPCo and OPCo, respectively, including carrying charges. These refunds were reflected as part of new transmission cost recovery riders, which became effective for 2007. The net effect of the new transmission cost recovery riders is to increase cost recoveries in 2006 over 2005 levels for CSPCo and OPCo by $27 million and $36 million, respectively. We anticipate a favorable net effect in 2007 over 2005 levels of $15 million and $18 million, respectively.

Distribution Service Reliability and Restoration Costs

In December 2003, the Ohio companies entered into a stipulation agreement regarding distribution service reliability. The stipulation agreement covered the years 2004 and 2005 and, among other features, established certain distribution service reliability measures for the Ohio companies to meet. In July 2006, based on a staff report on service reliability and responses filed by the Ohio companies, the PUCO directed the Ohio companies to earmark $10 million for future measures to improve service reliability without recovery. The PUCO further indicated that it will determine where and how to expend the $10 million.

The Ohio companies implemented storm cost recovery riders effective with September 2006 billings, to recover a portion of previously expensed incremental costs of restoring service disrupted by severe winter storms in December 2004 and January 2005. The riders will continue until they have collected the authorized amounts or one year, whichever is shorter.

As a result, at December 31, 2006 the Ohio companies have regulatory assets of $7 million for these costs.

Distribution Reliability Plan

In January 2006, the Ohio companies initiated a proceeding at the PUCO seeking a new distribution rate rider to fund enhanced distribution reliability programs. In the fourth quarter of 2006, as directed by the PUCO, the Ohio companies filed a proposed enhanced reliability plan. The plan contemplates recovering approximately $71 million in additional distribution revenue during an eighteen-month period beginning July 2007. A hearing is scheduled for April 2007. The OCC filed testimony, which argues that the Ohio companies should be required to improve their distribution service reliability with funds from their existing rates. Management is unable to predict the outcome of this proceeding.

Ormet

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load. The settlement agreement between CSPCo and OPCo, Ormet, its employees' union and certain other interested parties was approved by the PUCO in November 2006. The settlement agreement provides for the recovery in 2007 and 2008 by the Ohio companies of the difference between $43 per MWH to be paid by Ormet for power and a market price, if higher. The recovery will be accomplished by the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) Ohio franchise tax phase-out regulatory liability recorded in 2005 and, if that is not sufficient, an increase in RSP generation rates under the additional 4% provision of the RSPs. The $43 per MWH price to be paid by Ormet for generation services is above the industrial RSP generation tariff but below current market prices. In December 2006, the Ohio companies submitted a market price of $47.69 per MWH, which is pending PUCO approval.

Texas Rate Matters

TCC TEXAS RESTRUCTURING

TCC's True-up Proceedings and 2002 Securitization

Texas Restructuring Legislation established customer choice on January 1, 2002 and allowed electric utility companies to file for recovery of securitizable stranded generation plant costs, generation-related regulatory assets and non-securitizable other restructuring true-up items. These recoverable and refundable items were recorded as true-up regulatory assets and liabilities.

In 2002, TCC securitized $797 million to recover most of its stranded generation related regulatory assets. TCC sold its generating units to establish its stranded costs and recorded an impairment loss, which resulted in an additional net true-up regulatory asset recoverable under the Texas Restructuring Legislation. Beginning in 2002, TCC also recorded wholesale capacity auction true-up revenues and debt-related carrying costs on its net true-up regulatory asset, as additional true-up regulatory assets. Unrecognized equity carrying costs of $224 million included in the net stranded generation cost to be securitized will be recognized, as collected through transition charge securitization revenues, over the fourteen-year term of the securitization bonds.

In December 2004, predominately based on a PUCT disallowance of a specific stranded cost item in other true-up proceedings, TCC reduced its true-up regulatory assets.

In February 2006, the PUCT issued an order in TCC's True-up Proceeding, which determined that TCC's recoverable net true-up regulatory asset, for both securitizable net stranded generation cost regulatory assets and net other true-up items regulatory liabilities, was $1.475 billion as of September 30, 2005. The order disallowed specific items which included, among other things, a significant portion of TCC's wholesale capacity auction true-up revenues and a portion of TCC's stranded costs determined from the sale of the ERCOT generating units. Based on the PUCT's order in December 2005, TCC reduced its true-up regulatory asset. The order also identified a reduction in the net recoverable amount, which represented the present value benefit of ADITC and EDFIT related to the plants sold. See "TCC's 2006 CTC Proceeding" section below.

TCC will recover its PUCT-approved net true-up regulatory asset under the Texas Restructuring Legislation using two mechanisms: (a) by issuing securitization bonds in the amount of its net stranded generation costs and implementing a transition charge (TC) rate rider to collect the bond interest and principal over the term of the bonds and (b) by implementing a competition transition charge (CTC) rate rider credit to refund its net regulatory liability for other true-up items.

TCC's 2006 Securitization Proceeding

TCC filed an application in March 2006 requesting recovery through the issuance of securitization bonds of $1.804 billion of PUCT-approved securitizable net stranded generation costs plus subsequent carrying costs through August 31, 2006 and issuance costs. The securitization request excluded TCC's net regulatory liability for other true-up items, which will be refunded to customers using a CTC rate rider. See the "TCC's 2006 CTC Proceeding" section of this note. The PUCT approved a settlement in June 2006, which reduced the securitizable amount by $77 million and settled several issues and authorized the issuance of securitization bonds of $1.72 billion as of August 31, 2006. TCC issued securitization bonds on October 11, 2006 for $1.74 billion, which included additional issuance and carrying costs through October 11, 2006.

The securitization order provides for TCC to recover the securitization bond principal and related interest expense from customers over the fourteen-year term of the securitization bonds. Beginning in October 2006, the Securitized Transition Asset is amortized based on the ratio of annual transition revenues to total revenues over the fourteen-year TC collection period.

The June 2006 securitization order reduced the amount to be securitized and recovered by the present value of the ADITC and EDFIT benefit identified above in the April 2006 final true-up order. The securitization order also identified the present value cost-of-money benefit generated through the final year the securitization bonds will be outstanding (fourteen years) as an additional reduction. The present value cost-of-money benefit of $315 million resulted from the ADFIT related to the generation assets. However, rather than reducing the amount to be securitized, the PUCT ordered TCC to refund the ADFIT benefit through the CTC rate rider credit. See the "TCC's 2006 CTC Proceeding" section below for further details.

TCC's 2006 CTC Proceeding

In June 2006, TCC filed to refund, through a CTC rate rider credit, its net other true-up items and the ADFIT cost-of-money benefit less the present value benefit of ADITC and EDFIT, discussed above. An interim order required that the CTC refund begin in October 2006 pending a final CTC decision. The PUCT issued a final order in December 2006, which required that TCC refund $356 million of other true-up items and $19 million in estimated interest through the CTC over twenty-one months starting in October 2006. The ADFIT cost-of-money benefit of $315 million has a retrospective portion of $75 million which has been expensed and a prospective portion of $240 million which will be amortized to expense over the fourteen-year securitization bond term consistent with the period over which the cost-of-money benefit is generated and computed in the securitization order. The difference between the amount being refunded and the net other true-up regulatory liability of $219 million ($155 million at December 31, 2006) is predominantly due to the inclusion in the CTC refund of the $240 million unrecorded prospective portion of the ADFIT cost-of-money benefit less the $61 million present value benefit of ADITC and EDFIT applied to reduce the amount securitized above plus $42 million of interest through the date of securitization. The $103 million will be deferred pending a final determination of whether a normalization violation would occur. See "Other Texas Restructuring Matters" section below for further details.

TCC will accrue interest expense until its net CTC refund is completed. The interest expense on the net CTC amount is $22 million for the year ended December 31, 2006 and is included in Interest Expense on TCC's 2006 Consolidated Statement of Income.

Impairment Assessment of Net True-up Regulatory Assets

TCC performed a probability of recovery impairment test on TCC's recorded net true-up regulatory asset as of September 30, 2006, after receipt of the final securitization order, and again as of December 31, 2006 after receipt of the final CTC order. At both dates, TCC determined that the projected net cash flows from the securitization less the proposed CTC refund would provide more than sufficient net positive cash flows to recover TCC's recorded net true-up regulatory asset. Accordingly, no impairment was recorded at either date.

At December 31, 2006, TCC's Consolidated Balance Sheet reflects a securitization bond liability of $2.335 billion of which $595 million is from the initial 2002 securitization, a securitization transition asset of $2.158 billion of which $542 million is from the initial 2002 securitization, and a net true-up regulatory liability for other true-up items of $155 million as a result of the True-up Proceeding.

Texas District Court Appeal Proceedings

TCC appealed the PUCT orders seeking relief in both state and federal court on the grounds that the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. The significant items appealed by TCC are:

- The PUCT ruling that TCC did not comply with the statute and PUCT rules regarding the required auction of 15% of its Texas jurisdictional installed capacity, which led to a significant disallowance of capacity auction true-up revenues,
- The PUCT ruling that TCC acted in a manner that was commercially unreasonable, because it failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and it bundled out of the money gas units with the sale of its coal unit, which led to the disallowance of a significant portion of TCC's net stranded generation plant cost, and
- The two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation. See "TCC and TNC Deferred Fuel" and "TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" sections below.

Municipal customers and other intervenors appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries. On February 1, 2007, the Texas District Court judge hearing the various appeals issued a letter containing his preliminary determinations. He generally affirmed the PUCT's April 4, 2006 final true-up order with two significant exceptions. The judge determined that the PUCT erred when it determined TCC's stranded cost using the sale of assets method instead of the Excess Cost Over Market (ECOM) method to value TCC's nuclear plant. The judge also determined that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. However, the District Court did not rule that the carrying cost rate was inappropriate. He directed that these matters should be remanded to the PUCT to determine their specific impact on TCC's future revenues.

In response to a request by TCC, the District Court judge will hear additional argument on March 22, 2007 regarding use of the ECOM method to value TCC's nuclear plant stranded cost. TCC anticipates that the final judgment will be entered after that hearing. TCC intends to appeal any final adverse rulings of the District Court regarding these two matters along with certain of the judge's other preliminary determinations that affirm the PUCT's decisions. It is possible that the PUCT could also appeal any final adverse rulings regarding these two matters.

Although management cannot predict the ultimate outcome of these preliminary District Court determinations, any future remanded PUCT proceedings or any future court appeals, management concluded it is probable that the District Court's preliminary ruling regarding the use of an ECOM method in lieu of a sales method to determine securitizable stranded cost will not be upheld on appeal. The judge has also determined in his letter ruling that if the sales method is permitted for valuing the nuclear plant, the PUCT improperly reduced stranded costs in connection with the sales process, which could have a materially favorable effect on TCC.

Management also concluded if the District Court's preliminary carrying cost rate ruling is ultimately remanded to the PUCT for reconsideration, the PUCT could either confirm the existing carrying cost rate or redetermine the rate. If the PUCT changes the rate, it could result in a material adverse change to TCC's recoverable carrying costs. However, management cannot predict what actions, if any, the PUCT will take regarding the carrying costs.

If the District Court judge's original determination that TCC used an improper method to value its stranded costs is ultimately upheld on appeal, it could substantially reduce TCC's stranded costs. We cannot estimate the amount at this time, but the amount could exceed TCC's Common Shareholder's Equity at December 31, 2006. If it were finally concluded that the ECOM method must be used to value TCC's nuclear plant stranded cost, and/or that the PUCT's rule on carrying costs was invalid, it could, after the PUCT remand decisions, have a substantial adverse impact on future results of operations, cash flows and financial condition.

If TCC ultimately succeeds in its appeals on other than the above two matters, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, including their appeals of the two matters discussed above, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

OTHER TEXAS RESTRUCTURING MATTERS

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's true-up and securitization orders, the PUCT reduced net regulatory assets and the amount to be securitized by $51 million related to the present value of ADITC and by $10 million related to EDFIT associated with TCC's generation assets for a total reduction of $61 million.

TCC filed a request for a private letter ruling with the IRS in June 2005 regarding the permissibility under the IRS rules and regulations of the ADITC and EDFIT reduction proposed by the PUCT. The IRS issued its private letter ruling in May 2006, which stated that the PUCT's flow-through to customers of the present value of the ADITC and EDFIT benefits would result in a normalization violation. To address the matter, the PUCT agreed to allow TCC to defer an amount of the CTC refund totaling $103 million ($61 million in present value of ADITC and EDFIT associated with TCC's generation assets plus $42 million of related carrying costs) pending resolution of the normalization issue. It is anticipated that if the normalization issue is resolved consistent with the PUCT's treatment, TCC will then refund $103 million plus additional carrying costs. If such refund is ultimately determined to cause a normalization violation, TCC anticipates it will be permitted to retain the $61 million present value of ADITC and EDFIT plus carrying costs, favorably impacting future results of operations.

If a normalization violation occurs, it could result in TCC's repayment to the IRS of ADITC on all property, including transmission and distribution property, which approximates $104 million as of December 31, 2006, and a loss of TCC's right to claim accelerated tax depreciation in future tax returns. Tax counsel advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are returned to ratepayers under a nonappealable order. Management intends to continue its efforts to avoid a normalization violation that would adversely affect future results of operations and cash flows.

TCC and TNC Deferred Fuel

The TCC deferred fuel over-recovery regulatory liability is a component of the other true-up items net regulatory liability refunded through the CTC discussed above. In 2002, TCC and TNC filed with the PUCT seeking to reconcile fuel costs and establish their final deferred fuel balances. In its final fuel reconciliation orders, the PUCT ordered a reduction in TCC's and TNC's recoverable fuel costs for, among other things, the reallocation of additional AEP System off-system sales margins under a FERC-approved SIA. Both TCC and TNC appealed the PUCT's rulings regarding a number of issues in the fuel orders in state court and challenged the jurisdiction of the PUCT over the allocation of off-system sales margin allocations in the federal court. Intervenors also appealed the PUCT's rulings in state court.

In 2006, the Federal District Court issued orders precluding the PUCT from enforcing the off-system sales allocation portion of its ruling in the final TNC and TCC fuel reconciliation proceedings. The Federal court ruled, in both cases, that the FERC, not the PUCT, has jurisdiction over the allocation. The PUCT appealed both Federal District Court decisions to the United States Court of Appeals. In TNC's case, the Court of Appeals affirmed the District Court's decision. We await a ruling in TCC's appeal. If the PUCT's appeals are ultimately unsuccessful, TCC and TNC could record income of $16 million and $8 million, respectively, related to the reversal of the regulatory liabilities.

If the PUCT is unsuccessful in the federal court system, it or another interested party may file a complaint at the FERC to address the allocation issue. If a complaint at the FERC results in the PUCT's decisions being adopted by the FERC, there could be an adverse effect on results of operations and cash flows. An unfavorable FERC ruling may result in a retroactive reallocation of off-system sales margins from AEP East companies to AEP West companies under the then existing SIA allocation method. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the amounts from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits. Although management cannot predict the ultimate outcome of this federal litigation, management believes that its allocations were in accordance with the then existing FERC-approved SIA.

In January 2007, TCC began refunding as part of the CTC rate rider credit described above, $149 million of its $165 million over-recovered deferred fuel regulatory liability. The remaining $16 million refund relating to the favorable Federal District Court order may be subject to being refunded only upon a successful appeal by the PUCT. See "TNC's True-up Proceeding" section below for status of TNC's over-recovered fuel refund.

Excess Earnings

In 2005, the Texas Court of Appeals issued a decision finding the PUCT's prior order from the unbundled cost of service case requiring TCC to refund excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. To date, TCC refunded $55 million of excess earnings, including interest, of which $30 million went to the affiliated REP. In November 2005, the PUCT filed a petition for review with the Supreme Court of Texas seeking reversal of the Texas Court of Appeals' decision. The Supreme Court of Texas requested briefing, which has been provided, but it has not decided whether it will hear the case. If the Court of Appeals decision is upheld and the refund mechanism is found to be unlawful, the impact on TCC would then depend on: (a) how and if TCC is ordered by the PUCT to refund the excess earnings to ultimate customers and (b) whether it will be able to recover the amounts previously refunded to the REPs including the REP TCC sold to Centrica. Management is unable to predict the ultimate outcome of this litigation and its effect on future results of operations and cash flows.

TNC's True-up Proceeding

TNC filed with the PUCT in August 2005 to establish a credit rider to refund its $21 million net true-up regulatory liability. In December 2005, that proceeding was suspended, pending a final ruling from TNC's appeal to the federal court regarding the fuel proceeding (described above). In August 2006, the suspension was lifted and the proceeding resumed. The PUCT approved a settlement that recommended implementing a $13 million interim refund over six-months beginning in September 2006 of the net true-up regulatory liability, exclusive of the $8 million federal court fuel issue. TNC is accruing interest expense on the unrefunded balance and will continue to do so until the balance is fully refunded. TNC anticipates a final PUCT decision regarding this proceeding in 2007. The appeals to the state and federal courts are ongoing.

Texas Restructuring – SPP

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo's and approximately 3% of TNC's businesses were in SPP. We filed a petition in May 2006, requesting approval to transfer Mutual Energy SWEPCO L.P.'s (a subsidiary of AEP C&I Company, LLC) customers and TNC's facilities and certificated service territory located in the SPP area to SWEPCo. In January 2007, we received our final regulatory approval for the transfers. The transfers were effective February 2007. As required by the Arkansas Public Service Commission, SWEPCo will amend its fuel recovery tariff so that Arkansas customers do not pay the incremental cost of serving the additional load.

OTHER TEXAS RATE MATTERS

ERCOT PTB Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel and the cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's respective former affiliated REPs). In 2003, the District Court ruled the PUCT record lacked substantial evidence regarding the effect of loss of load due to retail competition on the generation requirements of both Mutual Energy WTU and Mutual Energy CPL and on the PTB rates. In an opinion issued in 2005, the Texas Court of Appeals reversed the District Court. The cities appealed the decision to the Supreme Court of Texas, which ordered full briefing. In February 2007, the Supreme Court of Texas denied review. No motions for rehearing have been filed and management believes the matter is now final.

TCC and TNC Energy Delivery Base Rate Filings

TCC and TNC each filed a rate case for recovery of the cost of transmission and distribution energy delivery services (wires) in Texas. TCC and TNC requested $81 million and $25 million in annual increases, respectively. Both requests include a return on common equity of 11.25% and the impact of the expiration of the CSW merger savings rate credits. We expect the new base wires rates to become effective, subject to refund, in the second quarter of 2007 with a decision from the PUCT expected in the third quarter of 2007.

SWEPCo PUCT Staff Review of Earnings

In October 2005, the staff of the PUCT reported the results of its review of SWEPCo's year end 2004 earnings. Based on the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff engaged SWEPCo in discussions to reconcile the earnings calculation and to consider possible ways to address the results. After those discussions, the PUCT staff informed SWEPCo in April 2006 that they would not pursue the matter further.

SWEPCo Fuel Reconciliation – Texas

In June 2006, SWEPCo filed a fuel reconciliation proceeding with the PUCT for its Texas retail operations. SWEPCo sought, in the proceedings, to include underrecoveries related to the reconciliation period of $50 million. In January 2007, intervenors filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced. The intervenor recommendations ranged from a $10 million to $28 million reduction. In February 2007, the PUCT staff filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced by $10 million. SWEPCo does not agree with the intervenor's or staff's recommendations and filed rebuttal testimony in February 2007. Management is unable to predict the outcome of this proceeding or its effect on future results of operations and cash flows.

Virginia Rate Matters

Virginia Restructuring

In April 2004, the Governor of Virginia signed legislation that extended the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004. Under the restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the restructuring law, APCo is deferring incremental environmental generation costs and incremental reliability costs for future recovery and is amortizing a portion of such deferrals commensurate with recovery. See the "APCo Virginia Environmental and Reliability Costs" section below for further details.

In February 2007, the Virginia legislature adopted amendments to its electric restructuring law. The amendments would shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation supply would return to a form of cost-based regulation. The Governor of Virginia has not yet signed this legislation. We are in the process of evaluating the impact of the legislation if it is signed into law.

APCo Virginia Environmental and Reliability Costs

The amended Virginia Electric Restructuring Act includes a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred on and after July 1, 2004. In 2005, APCo filed a request with the Virginia SCC and updated it through supplemental testimony seeking recovery of $21 million of incremental E&R costs incurred from July 1, 2004 through September 30, 2005.

In November 2006, the Virginia SCC issued a final order that rejected the staff's and the Hearing Examiner's interpretation of the law, which would have resulted in the inability to record a regulatory asset and would have ultimately prevented APCo from recovering its full incremental E&R costs incurred since July 1, 2004. The order approved an increase in APCo's rates to recover $21 million of incremental E&R costs previously incurred from

July 1, 2004 through September 30, 2005 by means of a surcharge, effective December 1, 2006 through November 30, 2007. As a result, in the fourth quarter of 2006, APCo commenced recovery of the approved E&R rate rider and deferred as a regulatory asset, $60 million of incremental E&R costs incurred from July 1, 2004 through September 30, 2006 based on the Virginia SCC's order and reversed $11 million of related AFUDC and capitalized interest, thereby increasing pre-tax earnings by $49 million. In addition, APCo has identified but not recognized $10 million of equity carrying costs on incremental E&R capital expenditures, which are not recognizable until collected. The order requires APCo to keep track, for true-up purposes, of base rate and surcharge recoveries of incremental E&R costs on a continuing basis to avoid any double recovery. During 2007 we will file for recovery of incremental E&R costs incurred from October 1, 2005 through September 30, 2006. The Virginia base rate case increase implemented October 2, 2006, subject to refund, is currently recovering an ongoing level of incremental E&R costs incurred since September 30, 2006 and as a result, we ceased deferring such costs incurred after that date.

APCo Virginia Base Rate Case

In May 2006, APCo filed a request with the Virginia SCC seeking an increase in base rates of $225 million to recover increasing costs including the cost of its investment in environmental equipment and a return on equity of 11.5%. In addition, APCo requested to move off-system sales margins, currently credited to customers through base rates, to the fuel factor where they can be trued-up to actual. APCo also proposed to share the off-system sales margins with customers with 40% going to reduce rates and 60% being retained by APCo. This proposed off-system sales fuel rate credit, which is estimated to be $27 million, partially offsets the $225 million requested increase in base rates for a net increase in base rate revenues of $198 million. The major components of the $225 million base rate request include $73 million for the impact of removing off-system sales margins from the rate year ending September 30, 2007, $60 million mainly due to projected net environmental plant additions through September 30, 2007 and $48 million for return on equity.

In May 2006, the Virginia SCC issued an order, consistent with Virginia law, placing the net requested base rate increase of $198 million into effect on October 2, 2006, subject to refund. The $198 million base rate increase being collected, subject to refund, includes recovery of incremental E&R costs projected to be incurred during the rate year beginning October 2006. These incremental E&R costs can be deferred and recovery sought through the E&R surcharge mechanism previously discussed if not recovered through base rates. In October 2006, the Virginia SCC staff filed their direct testimony recommending a base rate increase of $13 million with a return on equity of 9.9% and no off-system sales margin sharing. Other intervenors have recommended base rate increases ranging from $42 million to $112 million. Management reserved a portion of the revenue subject to refund that in its opinion is not probable of recovery. APCo filed rebuttal testimony in November 2006. Hearings were held in December 2006. APCo expects a ruling during 2007. We are unable to predict the ultimate effect of this filing on future revenues, cash flows and financial condition.

West Virginia Rate Matters

APCo and WPCo West Virginia Rate Case

In July 2006, the WVPSC approved a settlement agreement reached by APCo and WPCo and the WVPSC staff and intervenors in connection with a West Virginia rate case filed in 2005. The settlement agreement provided for an initial overall increase in rates of $44 million effective July 28, 2006 comprised of:

- A $56 million increase in Expanded Net Energy Cost (ENEC) for fuel, purchased power expenses, off-system sales credits and other energy-related costs (the ENEC is an expanded form of a fuel clause mechanism which includes all energy-related costs);
- A $23 million special construction surcharge providing recovery of the costs of scrubbers and the new Wyoming-Jacksons Ferry 765 kV line to date;
- An $18 million general base rate reduction resulting predominantly from a reduction in the return on equity to 10.5% and a $9 million reduction in depreciation expense which affects cash flows but not earnings; and
- A $17 million credit to refund a portion of deferred prior over-recoveries of ENEC of $51 million, recorded in regulatory liabilities on the Consolidated Balance Sheets, which will impact cash flows but not earnings.

In addition, the agreement provided a mechanism that allows APCo and WPCo to adjust their special construction surcharges annually for the timely recovery in each of the next three years of the incremental cost of ongoing environmental investments in scrubbers at APCo's Mountaineer and John Amos power plants and the costs of the new Wyoming-Jacksons Ferry 765 kV line. APCo and WPCo plan to file in March 2007 with the WVPSC for the first adjustment to their special construction surcharge, providing an incremental annual increase of $29 million to be effective July 1, 2007. APCo estimates annual increases in revenues of $14 million effective July 1, 2008 and $18 million effective July 1, 2009, subject to review by the WVPSC.

Under the settlement, the ENEC mechanism was reinstated effective July 1, 2006 with over/under recovery deferral accounting and annual ENEC proceedings to affect annual rate adjustments for changes in fuel, purchased power costs, off-system sales margins and other energy-related costs beginning in 2007. The settlement provides for the return to customers of the remaining $34 million of the prior ENEC regulatory liability plus interest at a LIBOR rate (London Interbank Offered Rate) on the unrefunded balance in future ENEC proceedings.

APCo IGCC

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer generating station in Mason County, WV. In January 2007, the WVPSC issued an order delaying the Commission's deadline for issuing an order on the certificate to December 3, 2007. The order also cancels a previously-approved procedural schedule. Through December 31, 2006, APCo deferred pre-construction IGCC costs totaling $10 million.

Indiana Rate Matters

I&M Depreciation Study Filing

In December 2005, I&M filed a petition with the IURC seeking authorization to revise its book depreciation rates applicable to its electric utility plant in service effective January 1, 2006. An order issued by the IURC in October 2006 did not dispute our revised depreciation accounting rates but, nevertheless, denied I&M's request to revise its book depreciation rates between base rate cases. In November 2006, I&M filed with the IURC a petition for reconsideration of the October order as well as a notice of appeal to the Indiana Court of Appeals. In January 2007, the IURC denied I&M's petition for reconsideration.

In February 2007, I&M withdrew its appeal of the IURC order and filed a new request with the IURC for approval of the revised book depreciation rates effective January 1, 2007. The filing included a settlement agreement entered into with the Indiana Office of the Utility Consumer Counselor that would provide direct benefits to I&M's customers if new depreciation rates are approved by the IURC. The direct benefits would include a $5 million credit in fuel costs and an approximate $8 million smart metering pilot program. In addition, if the agreement is approved, I&M would initiate a general rate proceeding on or before July 1, 2007 and initiate two studies, one to investigate a general smart metering program and the other to study the market viability of demand side management programs. Based on the depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately $69 million on an Indiana jurisdictional basis reflecting an NRC-approved 20-year extension of the Cook Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition was not a request for a change in customers' electric service rates. As proposed the book depreciation reduction would increase earnings but would not impact cash flows until rates are revised. I&M requested expeditious review and approval of its filing, but management cannot predict the outcome of the request.

Kentucky Rate Matters

KPCo Rate Filing

In March 2006, the KPSC approved a settlement agreement in KPCo's 2005 base rate case. The approved agreement provided for a $41 million annual increase in revenues effective March 30, 2006 and the retention of the existing environmental surcharge tariff. No return on equity was specified by the settlement terms except to note that KPCo will use a 10.5% return on equity to calculate the environmental surcharge tariff and AFUDC.

KPCo Environmental Surcharge Filing

In July 2006, KPCo filed for approval of an amended environmental compliance plan and revised tariff to implement an adjusted environmental surcharge. KPCo requested recovery of approximately $2 million of additional revenue in 2007 and an additional $6 million in 2008 for a total of $8 million of additional revenue. In January 2007, the KPSC issued an order approving KPCo's proposed plan and surcharge.

In November 2006, the Kentucky attorney general and the Kentucky Industrial Utility Consumers (KIUC) filed an appeal with the Kentucky Court of Appeals of the Franklin Circuit Court's 2006 order upholding the KPSC's 2005 Environmental Surcharge order. In its order, the KPSC approved KPCo's recovery of its environmental costs at its Big Sandy Plant and its share of environmental costs it incurs as a result of the AEP Power Pool capacity settlement. The KPSC allowed KPCo to recover these FERC-approved allocated costs, via the environmental surcharge, since the KPSC's first order in the environmental surcharge case in 1997. KPCo presently recovers $7 million a year in environmental surcharge revenues. At this time, management is unable to predict the outcome of this proceeding and its effect on KPCo's current environmental surcharge revenues or on the January 2007 KPSC order increasing KPCo's environmental rates.

Oklahoma Rate Matters

PSO Fuel and Purchased Power and its Possible Impact on AEP East companies and AEP West companies

In 2002, PSO under-recovered $44 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO proposed collection of those reallocated costs over eighteen months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocated purchased power costs over three years and PSO reduced its regulatory asset deferral by $2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. In January 2006, the OCC staff and intervenors issued supplemental testimony alleging that AEP deviated from the FERC-approved method of allocating off-system sales margins between AEP East companies and AEP West companies and among AEP West companies. The OCC staff proposed that the OCC offset the $42 million of under-recovered fuel with their proposed reallocation of off-system sales margins of $27 million to $37 million and with $9 million attributed to wholesale customers, which they claimed had not been refunded. In February 2006, the OCC staff filed a report concluding that the $9 million of reallocated purchased power costs assigned to wholesale customers had been refunded, thus removing that issue from their recommendation.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. The OCC has not ruled on appeals by intervenors of the ALJ's finding. The United States District Court for the Western District of Texas issued orders in September 2005 regarding a TNC fuel proceeding and in August 2006 regarding a TCC fuel proceeding, preempting the PUCT from reallocating off-system sales margins between the AEP East companies and AEP West companies. The federal court agreed that the FERC has sole jurisdiction over that allocation. The PUCT appealed the ruling. The United States Court of Appeals for the Fifth Circuit, issued a decision in December 2006 regarding the TNC fuel proceeding that affirmed the United States District Court ruling.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals other than the staff's original recommendation that PSO be allowed to recover the $42 million over three years and will defend its position. We believe that if the position taken by the federal courts in the Texas proceeding is applied to PSO's case, then the OCC should be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins between AEP East companies and AEP West companies. The OCC or another party could file a complaint at the FERC alleging the allocation of off-system sales margins adopted by PSO is improper, which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. To date, there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies.

In June 2005, the OCC issued an order directing its staff to conduct a prudence review of PSO's fuel and purchased power practices for the year 2003. The OCC staff filed testimony finding no disallowances in the test year data. The Attorney General of Oklahoma filed testimony stating that they could not determine if PSO's gas procurement activities were prudent, but did not include a recommended disallowance. However, an intervenor filed testimony in June 2006 proposing the disallowance of $22 million in fuel costs based on a historical review of potential hedging opportunities that he alleges existed during the year. A hearing was held in August 2006 and we expect a recommendation from the ALJ in 2007.

In February 2006, a law was enacted requiring the OCC to conduct prudence reviews on all generation and fuel procurement processes, practices and costs on either a two or three-year cycle depending on the number of customers served. PSO is subject to the required biennial reviews. In compliance with an OCC order, PSO is required to file its testimony by June 15, 2007. This proceeding will cover the year 2005.

Management cannot predict the outcome of the pending fuel and purchase power reviews or planned future reviews, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred. If the OCC disagrees and disallows fuel or purchased power costs including the unrecovered 2002 reallocation of such costs incurred by PSO, it would have an adverse effect on future results of operations and cash flows.

PSO Rate Filing

In November 2006, PSO filed a request to increase base rates $50 million for Oklahoma jurisdictional customers with a proposed effective date in the second quarter of 2007. PSO sought a return on equity of 11.75%. PSO also proposed a formula rate plan that, if approved as filed, will permit PSO to defer any unrecovered costs as a result of a revenue deficiency that exceeds 50 basis points of the allowed return on equity for recovery within twelve-months beginning six months after the test year. The formula would enable PSO to recover on a timely basis the cost of its new generation, transmission and distribution construction (including carrying costs during construction), provide the opportunity to achieve the approved return on equity and avoid recording a large amount of AFUDC that would have been recorded during the construction time period. Hearings are scheduled to begin in May, 2007.

Louisiana Rate Matters

SWEPCo Louisiana Fuel Inquiry

In March 2006, the Louisiana Public Service Commission (LPSC) closed its inquiry into SWEPCo's fuel and purchased power procurement activities during the period January 1, 2005 through October 31, 2005. The LPSC approved the LPSC staff's report, which concluded that SWEPCo's activities were appropriate and did not identify any disallowances or areas for improvement.

SWEPCo Louisiana Compliance Filing

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. Due to multiple delays, in April 2006, the LPSC and SWEPCo agreed to update the financial information based on a 2005 test year. SWEPCo filed updated financial review schedules in May 2006 showing a return on equity of 9.44% compared to the previously authorized return on equity of 11.1%.

In July 2006, the LPSC staff's consultants filed direct testimony recommending a base rate reduction in the range of $12 million to $20 million for SWEPCo's Louisiana jurisdiction customers, based on a proposed 10% return on equity. The recommended reduction range is subject to SWEPCo validating certain ongoing operations and maintenance expense levels. SWEPCo filed rebuttal testimony in October 2006 strongly refuting the consultants' recommendations. In December 2006, the LPSC staff's consultants filed reply testimony asserting that SWEPCo's Louisiana base rates are excessive by $17 million which includes a proposed return on equity of 9.8%. SWEPCo will file testimony in the first quarter of 2007. Hearings are expected to occur in early 2007. A decision is not expected until mid or late 2007. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ultimately ordered, it would adversely impact future results of operations and cash flows.

Michigan Rate Matters

Michigan Restructuring

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective on that date, the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total base rates in Michigan remain unchanged and reflect cost of service. As of December 31, 2006, none of I&M's customers elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory. As a result, management concluded that as of December 31, 2006, the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

FERC Rate Matters

RTO Formation/Integration Costs

In 2005, the FERC approved the amortization of approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs over 10 years. As of December 31, 2006 and 2005, the AEP East companies deferred $29 million and $31 million, respectively, of unamortized RTO and PJM formation/integration costs.

In a December 2005 order, the FERC approved the inclusion of a separate rate in the PJM AEP zone OATT to recover the amortization of deferred RTO formation/integration costs and related carrying costs not billed by PJM in monthly charges from November 1, 2005 through May 31, 2020. The rate, the result of a settlement, will be adjusted each year to collect $2 million on an annualized basis for 175 months. The AEP East companies will be responsible for paying the majority of the amortized costs assigned by the FERC to the AEP East zone since their internal load is approximately 85% of the transmission load in the AEP zone. As a result, the AEP East companies will need to recover the 85% through their retail rates.

In May 2006, the FERC approved a settlement that provides for recovery over a ten-year period of the deferred PJM-billed integration costs, including related carrying charges, of AEP, Commonwealth Edison Company (ComEd) and the Dayton Power and Light Company from all present zones of the PJM region, except the Virginia Electric & Power Company (VEPCo) zone. The net result of the settlement is that the AEP East companies will recover approximately 50% of the deferred PJM-billed integration costs from third parties, and will need to recover the remaining 50% through retail rates.

As a result of recently approved rate increases, CSPCo, OPCo, KPCo and APCo recover the amortization of RTO formation/integration costs billed to the AEP East companies in Ohio, Kentucky, Virginia (subject to refund) and West Virginia. In Indiana, I&M is subject to a rate cap until June 30, 2007 and is precluded from recovering its share of the deferred RTO costs until that date or until it can file for a rate increase in Indiana. I&M has not yet filed for recovery in Michigan.

If the Virginia, Indiana or Michigan commissions disallow recovery of any portion of the billed amortization of deferred RTO formation/integration costs, it could result in a write-off of up to 25% of the total remaining deferred balance, adversely impacting future results of operations and cash flows. In the event of a disallowance, we would appeal that decision to the appropriate state or federal courts.

Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

We eliminated through-and-out transmission service (T&O) revenues in accordance with FERC orders, and collected SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than collected. If a refund is ordered, we would also receive refunds related to the SECA rates we paid to third parties. The AEP East companies recognized gross SECA revenues as follows:

	Gross SECA Revenues Recognized
	(in millions)
Year Ended December 31, 2006 (a)	$ 43
Year Ended December 31, 2005	163
Year Ended December 31, 2004	14

(a) Represents revenues through March 31, 2006, when SECA rates expired, and excludes all provisions for refund.

Approximately $19 million of these recorded SECA revenues billed by PJM were never collected. The AEP East companies filed a motion with the FERC to force payment of these SECA billings.

In August 2006, the ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. The AEP East companies reached settlements with certain customers related to approximately $70 million of such revenues. The unsettled gross SECA revenues total approximately $150 million. If the ALJ's initial decision is upheld in its entirety, it would disallow $126 million of the AEP East companies' unsettled gross SECA revenues. It would also provide insignificant refunds of SECA rates paid by the AEP East companies. Based on the completed settlements and before the issuance of the ALJ's initial decision, the AEP East companies initially provided a reserve for $22 million in net refunds.

We, together with Exelon and DP&L, filed an extensive post-hearing brief and reply brief noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. We believe that the FERC should reject the initial decision because it is contrary to prior related FERC decisions, which are presently subject to rehearing. Furthermore, we believe the ALJ's findings on key issues are largely without merit. However, the initial decision is adversely impacting settlement negotiations. As a consequence we recorded an additional $15 million reserve in December 2006. Although we believe we have meritorious arguments, management cannot predict the ultimate outcome of any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision, it will have an adverse effect on future results of operations and cash flows.

The FERC PJM Regional Transmission Rate Proceeding

At our urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate AEP and other transmission owners for the regional transmission facilities they provide to PJM, which provides service for the benefit of customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC. This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway.

Parties to the regional rate proceeding proposed the following rate regimes:

- AEP/AP proposed a Highway/Byway rate design in which:
  - The cost of all transmission facilities in the PJM region operated at 345 kV or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The AEP/AP proposal would produce about $125 million in additional revenues per year for AEP from users in other zones of PJM.
  - The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's existing rate design.
- Two other utilities, Baltimore Gas & Electric Company (BG&E) and Old Dominion Electric Cooperative (ODEC), proposed a Highway/Byway rate that includes transmission facilities above 200 kV, which would produce lower revenues for AEP than the AEP/AP proposal.
- In a competing Highway/Byway proposal, a group of LSEs proposed rates that would include existing 500 kV and higher voltage facilities and new facilities above 200 kV in the Highway rate, which would produce considerably lower revenues for AEP than the AEP/AP proposal.
- In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design that would include all transmission facilities, which would produce higher transmission revenues for AEP than the AEP/AP proposal.

All of these proposals were challenged by a majority of other transmission owners in the PJM region, who favor continuation of the existing PJM rate design. Hearings were held in April 2006 and the ALJ issued an initial decision in July 2006. The ALJ found the existing PJM zonal rate design to be unjust and determined that it should be replaced. The ALJ found that the Highway/Byway rates proposed by AEP/AP and BG&E/ODEC and the Postage Stamp rate proposed by the FERC staff to be just and reasonable alternatives and recommended that the FERC staff's Postage Stamp rate proposal be adopted. The ALJ also found that the effective date of the rate change should be April 1, 2006 to coincide with SECA rate elimination. Because the Postage Stamp rate was found to produce greater cost shifts than other proposals, the judge also recommended that the design be phased-in. Without a phase-in, the Postage Stamp method would produce more revenue for AEP than the AEP/AP proposal. The phase-in of Postage Stamp rates would delay the full impact of that result until about 2012.

We filed briefs noting exceptions to the initial decision and replies to the exceptions of other parties. We argued that a phase-in should not be required. Nevertheless, AEP argued that if the FERC adopts the Postage Stamp rate and a phase-in plan, the revenue collections curtailed by the phase-in should be deferred and paid later with interest. A FERC decision is likely before mid-2007.

To recover these lost T&O and SECA rates, we sought to increase our retail rates in most of our states. The status of such state retail rate proceedings is as follows:

- In Kentucky, KPCo settled a rate case, which provided for the recovery of its share of the transmission revenue reduction in new rates effective March 30, 2006.
- In Ohio, CSPCo and OPCo recover their FERC-approved OATT that reflects their share of the full transmission revenue requirement retroactive to April 1, 2006 under a May 2006 PUCO order.
- In West Virginia, APCo settled a rate case, which provided for the recovery of its share of the T&O/SECA transmission revenue reduction beginning July 28, 2006.
- In Virginia, APCo filed a request for revised rates, which includes recovery of its share of the T&O/SECA transmission revenue reduction starting October 2, 2006, subject to refund.
- In Indiana, I&M is precluded by a rate cap from raising its rates until July 1, 2007.
- In Michigan, I&M has not filed to seek recovery of the lost transmission revenues.

We presently recover from retail customers approximately 85% of the reduction in transmission revenues of $128 million a year.

Once approved by the FERC, the favorable impacts of the new regional PJM rate design will flow directly to wholesale customers and to retail customers in West Virginia through the ENEC and to retail customers in Ohio upon PUCO approval of a filing we would make to reflect the new rates in the Transmission Cost Recovery Rider. In Kentucky, Indiana, Virginia and Michigan, the additional transmission revenues can be expected to reduce retail rates in future base rate proceedings.

Management is unable to predict whether the FERC will approve either the ALJ's decision or another regional rate design. We believe that the AEP/AP proposal or the Postage Stamp proposal combined with the retail rate recovery discussed above would be an effective replacement for the eliminated T&O and SECA rates. Future results of operations, cash flows and financial condition would be adversely affected if the approved FERC transmission rates are not sufficient to replace the lost T&O/SECA revenues. The resultant increase in the AEP East companies' unrecovered transmission costs are not fully recovered in retail rates on a timely basis especially in Indiana, where there is a rate freeze until June 30, 2007, and Michigan.

AEP East Transmission Revenue Requirement and Rates

In December 2005, the FERC approved an uncontested settlement which allowed increases in our wholesale transmission OATT rates in three steps: first, beginning retroactively on November 1, 2005, second, beginning on April 1, 2006 when the SECA revenues were eliminated and third, beginning on August 1, 2006 when the new Wyoming-Jacksons Ferry 765 kV line went into service. Wholesale transmission revenues increased approximately $23 million in 2006 due to this rate increase. We estimate that this rate increase will increase wholesale transmission revenues by $35 million in 2007.

Calpine Oneta Power, L.P.'s Request at the FERC for Reactive Power Compensation From SPP

In April 2003, Calpine Oneta Power (Calpine), an IPP, filed at the FERC a proposed rate schedule to charge SPP for reactive power from Calpine's generating facility. The FERC rate schedule included a fixed annual fee of $2 million. PSO, SWEPCo and, until February 2007, a small portion of TNC operated in SPP. In September 2006, the FERC issued an order reversing an ALJ initial decision, granting Calpine's request and requiring Calpine to make a compliance filing within 30 days. Our share of this SPP expense could be approximately 90% of the total amount billed by Calpine. Based on this information, in 2006 we recorded a provision, including interest, of $9 million for the retroactive reactive power liability. We requested rehearing at the FERC.

Calpine issued invoices to AEP for service and interest charges from June 2003 through December 2006 totaling $10 million. We objected to these invoices, in part, on the basis that Calpine seeks to collect its entire revenue requirement from us, leaving us with the risk of collecting the portion that may be owed by other service providers in the AEP zone of SPP. Meanwhile, in December 2006, SPP filed a new rate schedule. If the new rate schedule is approved, it will be generally applicable throughout SPP for reactive power service. If the FERC accepts the new rate, on a going forward basis from March 2007, we will owe an immaterial amount to Calpine for its reactive power production capability. The new tariff compensates generators for the reactive service they actually provide rather than the capability they possess.

Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. In March 2006, the FERC approved our proposed methodology effective April 1, 2006 and beyond. The approved allocation methodology for the AEP East companies and AEP West companies is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for a different method of sharing all such margins between both AEP East companies and AEP West companies, which effectively allowed the AEP West companies to share in PJM and MISO regional margins in the East. In February 2006, we filed with the FERC to remove TCC and TNC from the SIA and CSW Operating Agreement because they are in the final stages of exiting the generation business and have already ceased serving retail load. The FERC approved the removal of TCC and TNC from the SIA effective April 1, 2006 and CSW Operating Agreement effective May 1, 2006.

Our total trading and marketing margins are unaffected by the allocation methodology. The impact on future results of operations and cash flows will depend upon the level of future margins by region and the status of expanded net energy fuel clause recovery mechanisms and related off-system sales sharing mechanisms by state. However, the new allocation method is expected to increase the net system sales margins allocated to the AEP East companies, who flow considerably less of these margins through expanded fuel clause mechanisms and more in base rates than do the AEP West companies. As a result, the change in allocation methods should tend to increase future results of operations and cash flows.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2006	December 31, 2005	Notes
	(in millions)		
Regulatory Assets:			
Current Regulatory Asset –			
Under-recovered Fuel Costs	$ 38	$ 197	(c) (j)
SFAS 158 Regulatory Asset (Notes 2 and 9)	$ 875	$ -	(a)
SFAS 109 Regulatory Asset, Net (Note 13)	771	785	(c) (i)
Transition Regulatory Assets – Ohio and Virginia (Note 4)	185	306	(a) (k)
Designated for Securitization – Texas	-	1,436	(d)
Unamortized Loss on Reacquired Debt	105	110	(b) (l)
Unrealized Loss on Forward Commitments	89	92	(a) (i)
Texas Wholesale Capacity Auction True-up (Note 4)	-	77	(e)
Refunded Excess Earnings (Note 4)	56	55	(n)
Cook Nuclear Plant Refueling Outage Levelization	47	23	(a) (f)
Other	349	378	(c) (i)
Total Noncurrent Regulatory Assets	$ 2,477	$ 3,262	
Regulatory Liabilities:			
Current Regulatory Liability –			
Over-recovered Fuel Costs (o)	$ 37	$ 3	(c) (j)
Regulatory Liabilities and Deferred Investment Tax Credits:			
Asset Removal Costs	$ 1,610	$ 1,437	(g)
Deferred Investment Tax Credits	332	361	(c) (m)
Excess ARO for Nuclear Decommissioning Liability (Note 10)	323	271	(h)
Unrealized Gain on Forward Commitments	181	168	(a) (i)
TCC CTC Refund	155	238	(e)
Other	309	272	(c) (i)
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 2,910	$ 2,747	

(a) Does not earn a return.
(b) Amount effectively earns a return.
(c) Includes items both earning and not earning a return.
(d) Amount includes a carrying cost and was included in TCC's True-up Proceeding and securitized in October 2006. The cost of the securitization bonds will be recovered over a 14 year period. Amount is included within Securitized Transition Assets on the Consolidated Balance Sheet for 2006. See "TCC Texas Restructuring" section of Note 4.
(e) Net amounts were ordered to be refunded through the CTC. TCC's net refund began on an interim basis in October 2006. In a final order issued December 2006, the PUCT set the final net refund to be completed by June 2008. CTC refunds for TCC accrue interest until the refunds are completed. See "TCC's 2006 CTC Proceeding" section of Note 4.
(f) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.
(g) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(h) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. This amount earns a return, accrues monthly, and will be paid when the nuclear plant is decommissioned.
(i) Recovery/refund period - various periods.
(j) Recovery/refund period - 1 year.
(k) Recovery/refund period - up to 4 years.
(l) Recovery/refund period - up to 37 years.
(m) Recovery/refund period - up to 56 years.
(n) Recovery method and timing to be determined in future proceeding.
(o) Current Regulatory Liability – Over-recovered Fuel Costs are recorded in Other on our Consolidated Balance Sheets.

Merger with CSW

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

Summary of key provisions of Merger Rate Agreements beginning in the third quarter of 2000:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	Rate reduction of $221 million over 6 years. In 2006, TCC and TNC requested to have these rate reductions eliminated. See "TCC and TNC Energy Delivery Base Rate Filings" section of Note 4.
Indiana – I&M	Rate reduction of $67 million over 8 years.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on our financial statements.

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. Our insurance programs also generally provide coverage against loss arising from third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of a South Carolina domiciled protected-cell captive insurance company together with and/or in addition to various industry mutual and commercial insurance carriers and various Lloyds of London syndicates.

See Note 10 for a discussion of nuclear exposures and related insurance.

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

COMMITMENTS

The AEP System has substantial construction commitments to support its operations and environmental investments. Aggregate construction expenditures for 2007 for consolidated operations are estimated at approximately $3.5 billion plus $427 million of announced purchases of gas-fired generating units. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

Our subsidiaries enter into long-term contracts to acquire fuel for electric generation. The longest contract extends to the year 2029. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain conditions.

Our subsidiaries purchase materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination. We do not expect to incur penalty payments under these provisions that would materially affect our results of operations, cash flows or financial condition.

GUARANTEES

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

Letters Of Credit

We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. As the parent company, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At December 31, 2006, the maximum future payments for all the LOCs are approximately $26 million with maturities ranging from March 2007 to November 2007.

Guarantees Of Third-Party Obligations

<u>*SWEPCo*</u>

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides 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 Sabine Mining Company (Sabine), an entity consolidated under FIN 46. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of December 31, 2006, SWEPCo has collected approximately $29 million through a rider for final mine closure costs, of which approximately $12 million is recorded in Deferred Credits and Other and approximately $17 million is recorded in Asset Retirement Obligations on our Consolidated Balance Sheets.

SWEPCo is the only customer of Sabine and Sabine charges SWEPCo all its costs which are included in the cost of fuel and passed through SWEPCo's fuel clause.

Indemnifications And Other Guarantees

<u>*Contracts*</u>

We enter 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. The status of certain sales agreements is discussed in the "Dispositions" section of Note 8. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $2.2 billion (approximately $1 billion relates to the BOA litigation, see "Enron Bankruptcy" section of this note). There are no material liabilities recorded for any indemnifications.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed receipt of 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 are committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2006, the maximum potential loss for these lease agreements was approximately $56 million ($36 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

See Note 14 for disclosure of other lease residual value guarantees.

CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states allege that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR 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 alleged modifications occurred at our generating units over a twenty-year period. A bench trial on the liability issues was held during July 2005. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

Under the CAA, if a plant undertakes a major modification that 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 routine maintenance, replacement of degraded equipment or failed component or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. 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.

Cases are pending that could affect CSPCo's share of jointly-owned units at Beckjord, Zimmer, and Stuart Stations. Similar cases have been filed against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Court denied the Federal EPA's request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. The Federal EPA also proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

We are unable to estimate the loss or range of loss related to any contingent liability, if any, 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, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices of electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect our future results of operations, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. SWEPCo filed a response to the complaint in May 2005. A trial in this matter is scheduled for the second quarter of 2007.

In 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. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit.

We are unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on our results of operations, cash flows or financial condition.

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The defendants' motion to dismiss the lawsuits was granted in September 2005. The dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. We believe the actions are without merit and intend to defend against the claims.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

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

Superfund addresses clean-up of hazardous substances at disposal sites. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2006, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five sites. There are nine additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at two sites under state law. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

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

Plaquemine Cogeneration Facility

Juniper Capital L.P. (Juniper) constructed and financed our ownership interest in the Plaquemine Cogeneration Facility (the Facility) near Plaquemine, Louisiana and leased the Facility to us. We subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA.

In August 2006, we reached an agreement with Dow to sell the Facility to them and recorded a pretax impairment of $209 million (see "Dispositions" section of Note 8). The sale closed in November 2006. Upon closing, we repaid our recorded $525 million lease financing obligation, which was included in Long-term Debt on our Consolidated Balance Sheets at December 31, 2005.

Prior to the sale, Dow used a portion of the energy produced by the Facility and sold the excess energy. OPCo agreed to purchase up to approximately 800 MW of such excess energy from Dow for a twenty-year term. OPCo sold the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market until the sale of the Facility. With the sale of the Facility, OPCo terminated its purchase agreement with Dow.

TEM Litigation

OPCo agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) (now known as SUEZ Energy Marketing NA, Inc.) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA). Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming.

In September 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We alleged that TEM breached the PPA, and we sought a determination of our rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) provided a limited guaranty.

In August 2005, a federal judge ruled that TEM had breached the contract and awarded us damages of $123 million plus prejudgment interest. Any eventual proceeds will be recorded as a gain when received.

In September 2005, TEM posted a $142 million letter of credit as security pending appeal of the judgment. Both parties filed Notices of Appeal with the United States Court of Appeals for the Second Circuit, which heard oral argument on the appeals in December 2006. We cannot predict the ultimate outcome of this proceeding.

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 – Right to use of cushion gas agreements – In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America (BOA) and certain other banks (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 released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. In 2002, the BOA Syndicate filed a lawsuit against HPL in Texas state court seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage facility. In 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In August 2006, the Court of Appeals for the First District of Texas vacated the trial court's judgment and dismissed the BOA Syndicate's case. The BOA Syndicate did not seek review of 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's motion to have the case assigned to the judge who heard the case originally was granted. HPL intends to defend against any renewed claims by BOA.

In 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 facility 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 facility 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 objected to the Magistrate Judge's decision. In April 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York. HPL and BOA filed motions for summary judgment in the case pending in the Southern District of New York. The case in federal court in Texas is set for trial beginning April 2007.

In February 2007, the Judge in the New York action, after hearing oral argument on the motions for summary judgment, made a series of oral "informal findings" and submitted a written memorandum to the parties' counsel. In the memorandum to counsel, the Judge stated that he was denying several of AEP's motions for partial summary judgment, granting several of BOA motions for summary judgment and denying others. The substantive matters left open for further proceedings include the issue of the nature of the gas subject to BOA security interest and the value of that interest. The Judge stated that the memorandum to counsel is not an opinion or an order, and that no opinion or order will be issued until all motions pending before the Court have been decided. At this time we are unable to predict how the Judge will rule on the pending motions due to the complexity of those issues and the parties' disagreement over each issue. If the Judge issues a judgment directing AEP to pay an amount in excess of the gain on the sale of HPL described below and if AEP is unsuccessful in having the judgment reversed or modified, the judgment could have a material adverse effect on the results of operations and cash flow.

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 objected to Enron's attempted rejection of these agreements and filed an adversary proceeding contesting Enron's right to reject these agreements.

In 2005, we sold our interest in HPL. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. The determination of the gain on sale and the recognition of the gain are dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter.

Enron Bankruptcy – Commodity trading settlement disputes – In 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. We asserted our right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. In 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 sought to unwind the effects of the transaction. In 2005, the parties reached a settlement resulting in a pretax cost of approximately $46 million.

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 were counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities, the settlement agreement and management's analysis of the HPL-related purchase contingencies and indemnifications. As noted above, there is a dispute regarding the cushion gas agreement. Although management is unable to predict the outcome of the remaining 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 2002 and 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions were pending in federal District Court, Columbus, Ohio. In these actions, the plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. In July 2006, the Court entered judgment denying plaintiff's motion for class certification and dismissing all claims without prejudice. In August 2006, the plaintiffs filed a notice of appeal to the United States Court of Appeals for the Sixth Circuit. Briefing of this appeal was completed in December 2006 and the parties await the scheduling of oral argument. We intend to continue to defend against these claims.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were filed in California. In addition, a number of other cases were filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases were transferred to the United States District Court for the District of Nevada but subsequently were remanded to California state court. In 2005, the judge in Nevada dismissed three of the remaining cases (AEP was a defendant in one of these cases), on the basis of the filed rate doctrine. Plaintiffs in these cases appealed the decisions. We will continue to defend each case where an AEP company is a defendant.

Cornerstone Lawsuit

In 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 against a number of companies, including AEP and AEPES, making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. These cases were consolidated. In December 2006, we agreed to settle all claims with the plaintiffs without material impact on our results of operations or financial condition.

Energy Market Investigation

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. In 2003, the CFTC filed a complaint against AEP and AEPES in federal District Court. The CFTC alleged that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. In January 2005, we reached settlement agreements totaling $81 million with the CFTC, the U.S. Department of Justice and the FERC regarding investigations of past gas price reporting and gas storage activities. Our settlements did not admit nor should they be construed as an admission of violation of any applicable regulation or law. We made settlement payments to the agencies in 2005 in accordance with the respective contractual terms. The agencies' investigations and the CFTC litigation ended. During 2004, we provided for the settlements payment in the amount of $36 million (nondeductible for federal income tax purposes). There was no impact on 2006 or 2005 results of operations as a result of the settlements.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that we sold power at unjust and unreasonable prices. In December 2002, a FERC ALJ ruled in our favor and dismissed the complaint filed by the Nevada utilities. In 2001, the Nevada utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered as the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the complaint, held that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. In December 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. We have asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities.

7. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As a result of a 2005 company-wide staffing and budget review, we identified approximately 500 positions for elimination. We recorded pretax severance benefits expense of $28 million, which is primarily reflected in Other Operation and Maintenance on our 2005 Consolidated Statement of Income. Approximately 95% of the expense was within the Utility Operations segment. The following table shows the total 2005 expense recorded and the activity during 2005 and 2006, which eliminated the accrual as of June 30, 2006:

	Amount (in millions)
Total Expense	$ 28
Less: Total Payments	16
Accrual at December 31, 2005	12
Less: Total Payments	8
Less: Accrual Adjustments	4
Accrual at December 31, 2006	$ -

The December 31, 2005 accrual was primarily reflected in Current Liabilities – Other on our Consolidated Balance Sheets. The favorable accrual adjustments were recorded primarily in Other Operation and Maintenance on our Consolidated Statements of Income.

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

ACQUISITIONS

Acquisitions Anticipated Being Completed During the First Half of 2007

Darby Electric Generating Station (Utility Operations segment)

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the first half of 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

Lawrenceburg Generating Station (Utility Operations segment)

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for approximately $325 million and the assumption of liabilities of approximately $2 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the second quarter of 2007. The Lawrenceburg plant is located in Lawrenceburg, Indiana, adjacent to I&M's Tanners Creek Plant, and is a natural gas, combined cycle power plant with a generating capacity of 1,096 MW.

2006

None

2005

Waterford Plant (Utility Operations segment)

In May 2005, CSPCo signed a purchase and sale agreement with Public Service Enterprise Group Waterford Energy LLC, a subsidiary of PSEG, for the purchase of the Waterford Plant in Waterford, Ohio. The Waterford Plant is a natural gas, combined cycle power plant with a generating capacity of 821 MW. This transaction was completed in September 2005 for $218 million and the assumption of liabilities of approximately $2 million.

Monongahela Power Company (Utility Operations segment)

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power Company (Monongahela Power), which includes approximately 29,000 customers. In August 2005, we agreed to terms of a transaction, which included the transfer of Monongahela Power's Ohio customer base and the assets, at net book value, that serve those customers to CSPCo. This transaction was completed in December 2005 for approximately $46 million and the assumption of liabilities of approximately $2 million. In addition, CSPCo paid $10 million to compensate Monongahela Power for its termination of certain litigation in Ohio. Therefore, beginning January 1, 2006, CSPCo began serving customers in this additional portion of its service territory. CSPCo's $10 million payment was recorded as a regulatory asset and will be recovered with a carrying cost from all of CSPCo's customers over approximately 5 years. Also included in the transaction was a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, will provide the power requirements of the acquired customers through May 31, 2007.

Ceredo Generating Station (Utility Operations segment)

In August 2005, APCo signed a purchase and sale agreement with Reliant Energy for the purchase of the Ceredo Generating Station located near Ceredo, West Virginia. The Ceredo Generating Station is a natural gas, simple cycle power plant with a generating capacity of 505 MW. This transaction was completed in December 2005 for $100 million.

2004

None

DISPOSITIONS

2006

Compresion Bajio S de R.L. de C.V. (All Other)

In January 2002, we acquired a 50% interest in Compresion Bajio S de R.L. de C.V. (Bajio), a 600 MW power plant in Mexico. We received an indicative offer for Bajio in September 2005, which resulted in a pretax other-than-temporary impairment charge of approximately $7 million. The impairment amount is classified in Investment Value Losses on our 2005 Consolidated Statement of Income. We completed the sale in February 2006 for approximately $29 million with no effect on our 2006 results of operations.

Plaquemine Cogeneration Facility (All Other)

In August 2006, we reached an agreement to sell our Plaquemine Cogeneration Facility (the Facility) to Dow Chemical Company (Dow) for $64 million. We recorded a pretax impairment of $209 million ($136 million, net of tax) in the third quarter of 2006 based on the terms of the agreement to sell the Facility to Dow. We recorded the impairment in Asset Impairments and Other Related Charges on our 2006 Consolidated Statement of Income. The Facility does not meet the criteria for discontinued operations reporting.

We completed the sale in the fourth quarter of 2006. Excluding the 2006 impairment of $209 million discussed above, the effect of the sale on our 2006 results of operations was not significant. In addition to the cash proceeds, the sale agreement allows us to participate in gross margin sharing on the Facility for five years. As a result of the sale, Dow reduced an existing below-current-market long-term power supply contract with us in Texas by 50 MW and we retained the right to any judgment paid by TEM for breaching the original Power Purchase and Sale Agreement. See "TEM Litigation" section of Note 6.

Intercontinental Exchange, Inc. (ICE) Initial Public Offering (All Other)

See the following 2005 disclosure "Intercontinental Exchange, Inc. (ICE) Initial Public Offering" for information regarding sales in 2006.

<u>2005</u>

Intercontinental Exchange, Inc. (ICE) Initial Public Offering (All Other)

In November 2000, we made our initial investment in ICE. An initial public offering (IPO) occurred on November 15, 2005. We sold approximately 2.1 million shares (71% of our investment in ICE) in the fourth quarter of 2005 and recognized a $47 million pretax gain ($30 million, net of tax). During 2006, we sold approximately 0.6 million shares and recognized a $39 million pretax gain ($25 million, net of tax). We recorded the gains in Interest and Investment Income on our Consolidated Statements of Income. Our remaining investment of 0.3 million shares is recorded in Other Temporary Cash Investments on our Consolidated Balance Sheets.

Houston Pipe Line Company LP (HPL) (All Other)

During 2005, we sold our interest in HPL, 30 billion cubic feet (BCF) of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. Although the assets were legally transferred, it is not possible to determine all costs associated with the transfer until the Bank of America (BOA) litigation is resolved. Accordingly, we recorded the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $380 million and $379 million as of December 31, 2006 and 2005, respectively, which are reflected in Deferred Credits and Other on our Consolidated Balance Sheets. We provided an indemnity to the purchaser in an amount up to the purchase price for damages, if any, arising from litigation with BOA and a potential resulting inability to use the cushion gas (see "Enron Bankruptcy" section of Note 6). The HPL operations do not meet the criteria to be shown as discontinued operations due to continuing involvement associated with various contractual obligations. Significant continuing involvement includes cash flows from long-term gas contracts with the buyer through 2008 and the cushion gas arrangement. In addition, we hold forward gas contracts, with expirations through 2010, not sold with the gas pipeline and storage assets. We manage the commodity price risk associated with these forward gas contracts to limit our price risk exposure principally by entering into equal and offsetting contracts. For the year ended December 31, 2006, the change in the mark-to-market value of these contracts was less than $100,000.

Pacific Hydro Limited (All Other)

In March 2005, we signed an agreement with Acciona, S.A. for the sale of our equity investment in Pacific Hydro Limited for approximately $88 million. The sale was contingent on Acciona obtaining a controlling interest in Pacific Hydro Limited. The sale was consummated in July 2005 and we recognized a pretax gain of $56 million. This gain is classified in Gain on Disposition of Equity Investments, Net on our 2005 Consolidated Statement of Income.

Texas REPs (Utility Operations segment)

In December 2002, we sold two of our Texas REPs to Centrica, a UK-based provider of retail energy. The sales price was $146 million plus certain other payments including an earnings-sharing mechanism (ESM) for Centrica and us to share in the earnings of the sold business for the years 2003 through 2006. The method of calculating the annual earnings-sharing amount was included in the Purchase and Sales Agreement and was amended through a series of agreements that we and Centrica entered in March 2005. Also in March 2005, we received payments related to the ESM of $45 million and $70 million for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in 2005. In March 2006, we received a payment of $70 million related to the ESM for 2005. The ESM payment for 2006 is contingent on Centrica's operating results and is contractually capped at $20 million. The payments are reflected in (Gain) Loss on Disposition of Assets, Net on our Consolidated Statements of Income.

Texas Plants – South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCC's 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal with terms similar to the original agreement. In September 2004, we entered into sales agreements with two of our nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. The sale was completed for approximately $314 million and the assumption of liabilities of $22 million in May 2005 and did not have a significant effect on our results of operations. The plant did not meet the "component-of-an-entity" criteria because it did not have cash flows that could be clearly distinguished operationally. The plant also did not meet the "component-of-an-entity" criteria for financial reporting purposes because it did not operate individually, but rather as a part of the AEP System which included all of the generation facilities owned by our Registrant Subsidiaries.

<u>2004</u>

Pushan Power Plant (All Other)

In 2002, we began active negotiations to sell our interest in the Pushan Power Plant (Pushan) in Nanyang, China to our minority interest partner. The sale was completed in March 2004 for $61 million. The effect of the sale on our 2004 results of operations was not significant. Results of operations of Pushan are classified in Discontinued Operations on our 2004 Consolidated Statement of Income. See "Discontinued Operations" section of this note for additional information.

LIG Pipeline Company and its Subsidiaries (All Other)

As a result of our 2003 decision to exit our noncore businesses, we actively marketed LIG Pipeline Company, which had approximately 2,000 miles of natural gas gathering and transmission pipelines in Louisiana, and five gas processing facilities that straddle the system. In January 2004, a decision was made to sell LIG's pipeline and processing assets separate from LIG's gas storage assets. (See "Jefferson Island Storage & Hub, LLC" section of this note for further information.) In February 2004, we signed a definitive agreement to sell LIG Pipeline Company, which owned all of the pipeline and processing assets of LIG. The sale of LIG Pipeline Company and its assets for $76 million was completed in April 2004 and the impact on results of operations in 2004 was not significant. The results of operations are classified in Discontinued Operations on our 2004 Consolidated Statement of Income. See "Discontinued Operations" section of this note for additional information.

Jefferson Island Storage & Hub, LLC (All Other)

In August 2004, a definitive agreement was signed to sell the gas storage assets of Jefferson Island Storage & Hub, LLC (JISH). The sale of JISH and its assets for $90 million was completed in October 2004. The sale resulted in a pretax loss of $12 million ($2 million, net of tax). The results of operations and loss on sale of JISH are classified in Discontinued Operations on our 2004 Consolidated Statement of Income. See "Discontinued Operations" section of this note for additional information.

AEP Coal, Inc. (All Other)

In October 2001, we acquired out of bankruptcy certain assets and assumed certain liabilities of nineteen coal mine companies formerly known as "Quaker Coal" and renamed "AEP Coal, Inc." During 2002, the coal operations suffered from a decline in prices and adverse mining factors resulting in significantly reduced mine productivity and revenue. Based on an extensive review of economically accessible reserves and other factors, future mine productivity and production was expected to continue below historical levels.

In 2003, as a result of management's decision to exit our noncore businesses, we retained an advisor to facilitate the sale of AEP Coal, Inc. In March 2004, an agreement was reached to sell assets, exclusive of certain reserves and related liabilities, of the mining operations of AEP Coal, Inc. We received approximately $9 million cash and the buyer assumed an additional $11 million in future reclamation liabilities. We retained an estimated $37 million in future reclamation liabilities which has since been reduced to approximately $14 million. The sale closed in April 2004 and the effect of the sale on our 2004 results of operations was not significant.

Independent Power Producers (Generation and Marketing 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). 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. A pretax impairment of $2 million was recorded in June 2004 (recorded to Investment Value Losses) to decrease the carrying value of the Colorado plant investments to their estimated sales price, less selling expenses. We closed on the sale of all four investments in 2004. The sale resulted in a pretax gain of $105 million ($64 million, net of tax) generated primarily from the sale of the two Florida IPPs which were not originally impaired. The gain was recorded in Gain on Disposition of Equity Investments, Net on our 2004 Consolidated Statement of Income.

U.K. Generation (All Other)

In December 2001, we acquired two coal-fired generation plants in the U.K. for a cash payment of $942 million and assumption of certain liabilities. Subsequently and continuing through 2002, wholesale U.K. electric power prices declined sharply as a result of domestic over-capacity and static demand. External industry forecasts and our own projections made during the fourth quarter of 2002 indicated that this situation may extend many years into the future.

In the fourth quarter of 2003, the U.K. generation plants were determined to be noncore assets and management engaged an investment advisor to assist in determining the best methodology to exit the U.K. business. In July 2004, we completed the sale of substantially all operations and assets within the U.K. The sale included our two coal-fired generation plants (Fiddler's Ferry and Ferrybridge), related coal assets, and a number of related commodities contracts for approximately $456 million. The sale resulted in a pretax gain of $266 million ($128 million, net of tax). As a result of the sale, the buyer assumed an additional $46 million in future reclamation liabilities and $10 million in pension liabilities. The remaining assets and liabilities include certain physical power and capacity positions and financial coal and freight swaps. Substantially all of these positions matured or were settled with the applicable counterparties during 2005. The results of operations and gain on sale are included in Discontinued Operations, Net of Tax on our Consolidated Statements of Income for the year ended December 31, 2004. See "Discontinued Operations" section of this note for additional information.

Texas Plants – TCC Generation Assets (Utility Operations segment)

In relation to the implementation of the Texas Restructuring Legislation, we signed an agreement in March 2004 to sell eight natural gas plants, one coal-fired plant and one hydro plant to a nonrelated joint venture. The sale was completed in July 2004 for approximately $428 million, net of adjustments. The sale did not have a significant effect on our 2004 results of operations.

South Coast Power Limited (All Other)

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 MW, combined-cycle, gas turbine power station located in Shoreham, England. In 2003, management determined that our U.K. operations were no longer part of our core business and as a result, a decision was made to exit the U.K. market. In September 2004, we completed the sale of our 50% ownership in SCPL for $47 million, resulting in a pretax gain of $48 million ($31 million, net of tax). This gain was recorded in Gain on Disposition of Equity Investments, Net on our 2004 Consolidated Statement of Income.

Excess Real Estate (Utility Operations segment)

In June 2004, we entered into negotiations to sell an under-utilized building in Dallas, Texas obtained through our merger with CSW in 2000. A pretax impairment of $3 million was recorded in Other Operation and Maintenance on our Consolidated Statements of Income during the second quarter of 2004 to write down the value of the office building to the current estimated sales price, less estimated selling expenses. In October 2004, we completed the sale of the Dallas office building for $8 million. The sale did not have a significant effect on our results of operations.

Numanco LLC (All Other)

In November 2004, we completed the sale of Numanco LLC for a sale price of $25 million. Numanco was a provider of staffing services to the utility industry. The sale did not have a significant effect on our 2004 results of operations.

DISCONTINUED OPERATIONS

Management periodically assesses our overall business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify the operations of those businesses or operations as discontinued operations. The assets and liabilities of these discontinued operations are classified in Assets Held for Sale and Liabilities Held for Sale until the time that they are sold.

Certain of our operations were determined to be discontinued operations and are classified as such in 2006, 2005 and 2004. Results of operations of these businesses are classified as shown in the following table:

	SEE-BOARD (a)	Pushan Power Plant	LIG (b)	U.K. Generation (c)	Total
			(in millions)		
2006 Revenue	$ -	$ -	$ -	$ -	$ -
2006 Pretax Income	-	-	-	9	9
2006 Earnings, Net of Tax	5	-	-	5	10
2005 Revenue (Expense)	$ 13	$ -	$ -	$ (7)	$ 6
2005 Pretax Income (Loss)	10	-	-	(13)	(3)
2005 Earnings (Loss), Net of Tax	24	-	5	(2)	27
2004 Revenue	$ -	$ 10	$ 165	$ 125	$ 300
2004 Pretax Income (Loss)	(3)	9	(12)	164	158
2004 Earnings (Loss), Net of Tax	(2)	6	(12)	91	83

(a) Relates to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.
(b) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC. The 2005 amounts relate to purchase price true-up adjustments and tax adjustments from the sale.
(c) The 2006 amounts relate to a release of accrued liabilities for the London office lease and tax adjustments from the sale. The 2005 amounts relate to purchase price true-up adjustments and tax adjustments from the sale.

ASSET IMPAIRMENTS, INVESTMENT VALUE LOSSES AND OTHER RELATED CHARGES

2006

We recorded a pretax impairment of assets totaling $209 million as a result of the terms of our agreement to sell the Plaquemine Cogeneration Facility to Dow. See “Plaquemine Cogeneration Facility” section of this note for additional information regarding this sale.

2005

We recorded pretax impairments of assets totaling $46 million ($39 million related to asset impairments and $7 million related to an equity investment impairment) that reflected our decision to retire two generation units and our decision to exit noncore businesses and other factors as follows:

Conesville Units 1 and 2 (Utility Operations segment)

In the third quarter of 2005, following management’s extensive review of the commercial viability of our generation fleet, management committed to a plan to retire CSPCo’s Conesville Units 1 and 2 before the end of their previously estimated useful lives. As a result, Conesville Units 1 and 2 were considered retired as of the third quarter of 2005.

We recognized a pretax charge of approximately $39 million in 2005 related to our decision to retire the units. The impairment amount is classified in Asset Impairments and Other Related Charges on our 2005 Consolidated Statement of Income.

Compresion Bajio S de R.L. de C.V. (All Other)

In January 2002, we acquired Bajio. A pretax other-than-temporary impairment charge of $13 million was recognized in December 2004 based on an indicative bid, which did not result in a sale.

In September 2005, a pretax other-than-temporary impairment charge of approximately $7 million was recognized based on an indicative offer received in September 2005. Both the 2005 and 2004 impairment amounts are classified as Investment Value Losses on our Consolidated Statements of Income. The sale was completed in February 2006 without significant effect on our 2006 results of operations.

2004

We recorded pretax impairments of assets (including goodwill) and investments totaling $18 million ($15 million related to equity investments recorded in Investment Value Losses and $3 million related to charges recorded for excess real estate in Other Operation and Maintenance on our Consolidated Statement of Income) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit noncore businesses and other factors.

The categories of impairments and gains on dispositions include:

	Year Ended December 31,		
	2006	**2005**	**2004**
Asset Impairments and Other Related Charges (Pretax)		(in millions)	
Plaquemine Cogeneration Facility	$ 209	$ -	$ -
Conesville Units 1 and 2	-	39	-
Total	$ 209	$ 39	$ -
(Gain) Loss on Disposition of Assets, Net (Pretax)			
Texas REPs	$ (70)	$ (112)	$ -
Miscellaneous Property, Plant and Equipment	1	(8)	(4)
Total	$ (69)	$ (120)	$ (4)
Investment Value Losses (Pretax)			
Independent Power Producers	$ -	$ -	$ (2)
Bajio	-	(7)	(13)
Total	$ -	$ (7)	$ (15)
Gain on Disposition of Equity Investments, Net (Pretax)			
Independent Power Producers	$ -	$ -	$ 105
South Coast Power Limited	-	-	48
Pacific Hydro Limited	-	56	-
Other	3	-	-
Total	$ 3	$ 56	$ 153

ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to Golden Spread Electric Cooperative, Inc. (Golden Spread), subject to a right of first refusal by the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville (the nonaffiliated co-owners). By May 2004, we received notice from the nonaffiliated co-owners 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 the nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. Golden Spread challenged these agreements in State District Court in Dallas County. Golden Spread alleges that the Public Utilities Board of the City of Brownsville exceeded its legal authority and that the Oklahoma Municipal Power Authority did not exercise its right of first refusal in a timely manner. Golden Spread requested that the court declare the nonaffiliated co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of Golden Spread in October 2005. TCC and the nonaffiliated co-owners filed an appeal to the Court of Appeals for the Fifth District at Dallas.

In May 2006, the Court of Appeals for the Fifth District at Dallas reversed the trial court's judgment in favor of Golden Spread and held that the City of Brownsville properly exercised its right of first refusal to acquire TCC's share of Oklaunion. Golden Spread requested a rehearing in the matter, which was denied. Golden Spread then appealed to the Supreme Court of Texas and on December 15, 2006, its Petition for review was denied. Various contract claims, between the parties, that were severed from the appeal on the right of first refusal are pending in the District Court of Dallas County.

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville. The sale did not have a significant effect on our results of operations nor do we expect the remaining litigation to have a significant effect on our results of operations.

TCC's assets related to the Oklaunion Power Station are classified in Assets Held for Sale on our Consolidated Balance Sheets at December 31, 2006 and 2005. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by our Registrant Subsidiaries.

The Assets Held for Sale at December 31, 2006 and 2005 are as follows:

	December 31,	
	2006	**2005**
Texas Plants	**(in millions)**	
Other Current Assets	$ 1	$ 1
Property, Plant and Equipment, Net	43	43
Total Assets Held for Sale	$ 44	$ 44

9. BENEFIT PLANS

We sponsor two qualified pension plans and two nonqualified pension plans. A substantial majority of our employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. We sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees. We implemented FASB Staff Position FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" in 2004. The Medicare subsidy reduced our SFAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million contributing to an actuarial gain in 2004. As a result, the tax-free subsidy reduced 2004's net periodic postretirement benefit cost by a total of $29 million, including $12 million of amortization of the actuarial gain, $4 million of reduced service cost, and $13 million of reduced interest cost on the APBO.

In December 2006, we implemented SFAS 158. The effect of this standard on our financial statements was a pretax AOCI adjustment of $1,236 million that was offset by a SFAS 71 regulatory asset of $875 million and a deferred income tax asset of $126 million resulting in a net of tax AOCI equity reduction of $235 million. See Note 2.

The following tables provide a reconciliation of the changes in the plans' projected benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2006, and their funded status as of December 31 of each year:

Projected Pension Obligations, Plan Assets, Funded Status as of December 31, 2006 and 2005

	Pension Plans		Other Postretirement Benefit Plans	
	2006	**2005**	**2006**	**2005**
Change in Projected Benefit Obligation		**(in millions)**		
Projected Obligation at January 1	$ 4,347	$ 4,108	$ 1,831	$ 2,100
Service Cost	97	93	39	42
Interest Cost	231	228	102	107
Participant Contributions	-	-	21	20
Actuarial (Gain) Loss	(293)	191	(55)	(320)
Plan Amendments	2	-	-	-
Benefit Payments	(276)	(273)	(112)	(118)
Medicare Subsidy Accrued	-	-	(8)	-
Projected Obligation at December 31	$ 4,108	$ 4,347	$ 1,818	$ 1,831
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 4,143	$ 3,555	$ 1,172	$ 1,093
Actual Return on Plan Assets	470	224	127	70
Company Contributions	9	637	94	107
Participant Contributions	-	-	21	20
Benefit Payments	(276)	(273)	(112)	(118)
Fair Value of Plan Assets at December 31	$ 4,346	$ 4,143	$ 1,302	$ 1,172
Funded Status				
Funded Status at December 31	$ 238	$ (204)	$ (516)	$ (659)
Unrecognized Net Transition Obligation	-	-	-	152
Unrecognized Prior Service Cost (Benefit)	-	(9)	-	5
Unrecognized Net Actuarial Loss	-	1,266	-	471
Net Asset (Liability) Recognized	$ 238	$ 1,053	$ (516)	$ (31)

Amounts Recognized on the Balance Sheets as of December 31, 2006 and 2005

	Pension Plans		Other Postretirement Benefit Plans	
	2006	**2005**	**2006**	**2005**
		(in millions)		
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 320	$ 1,099	$ -	$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(8)	-	(5)	-
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(74)	(46)	(511)	(31)
Funded Status	238		(516)	
Regulatory Assets	582	N/A	293	N/A
Deferred Income Taxes	60	10	66	N/A
Additional Minimum Liability	N/A	(35)	N/A	N/A
Intangible Asset	N/A	6	N/A	N/A
Accumulated Other Comprehensive Income (Loss), Net of Tax	112	19	123	N/A
Total	$ 992	$ 1,053	$ (34)	$ (31)

N/A = Not Applicable

SFAS 158 Amounts Recognized in Accumulated Other Comprehensive Income (AOCI) as of December 31, 2006

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 759	$ 354
Prior Service Cost (Credit)	(5)	4
Transition Obligation	-	124
Pretax AOCI	$ 754	$ 482
Recorded as		
Regulatory Assets	$ 582	$ 293
Deferred Income Taxes	60	66
Net of tax AOCI	112	123
Pretax AOCI	$ 754	$ 482

We recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of our regulated operations that for ratemaking purposes will be deferred for future recovery.

Pension and Other Postretirement Plans' Assets

The asset allocations for our pension plans at the end of 2006 and 2005, and the target allocation for 2007, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
Asset Category	2007	2006	2005
		(in percentage)	
Equity Securities	65	63	62
Real Estate	5	6	4
Debt Securities	28	26	25
Cash and Cash Equivalents	2	5	9
Total	100	100	100

The asset allocations for our other postretirement benefit plans at the end of 2006 and 2005, and target allocation for 2007, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
Asset Category	2007	2006	2005
		(in percentage)	
Equity Securities	65	66	68
Debt Securities	33	32	30
Other	2	2	2
Total	100	100	100

Our investment strategy for our employee benefit trust funds is to use a diversified portfolio of investments to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk. To minimize risk, our employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. Our investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. Our investment policies prohibit investment in AEP securities, with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies. Because of the $320 million contribution at the end of 2005 the actual pension asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2006.

The value of our pension plans' assets increased to $4.3 billion at December 31, 2006 from $4.1 billion at December 31, 2005. The qualified plans paid $267 million in benefits to plan participants during 2006 (nonqualified plans paid $9 million in benefits). The value of AEP's Postretirement Plans' assets increased to $1.3 billion in December 31, 2006 from $1.2 billion at December 31, 2005. The Postretirement Plans paid $112 million in benefits to plan participants during 2006.

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

Accumulated Benefit Obligation

	December 31, 2006	December 31, 2005
	(in millions)	
Qualified Pension Plans	$ 3,861	$ 4,053
Nonqualified Pension Plans	78	81
Total	$ 3,939	$ 4,134

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2006 and 2005 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2006	2005
	(in millions)	
Projected Benefit Obligation	$ 82	$ 84
Accumulated Benefit Obligation	$ 78	$ 81
Fair Value of Plan Assets	-	-
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	$ 78	$ 81

We made a contribution of $626 million in 2005 to meet our goal of fully funding all qualified pension plans by the end of 2005.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
	2006	2005	2006	2005
	(in percentages)			
Discount Rate	5.75	5.50	5.85	5.65
Rate of Compensation Increase	5.90(a)	5.90(a)	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A = Not Applicable

To determine a discount rate, we use a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2006, the rate of compensation increase assumed varies with the age of the employee, ranging from 5.0% per year to 11.5% per year, with an average increase of 5.90%.

Estimated Future Benefit Payments and Contributions

Information about the 2007 expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

Employer Contribution	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Required Contributions (a)	$ 8	N/A
Additional Discretionary Contributions	-	$ 82

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor and to fund nonqualified benefit payments.

N/A = Not Applicable

The contribution to the pension plans is based on the minimum amount required by the U.S. Department of Labor and the amount to fund nonqualified benefit payments, plus the additional discretionary contributions to fully fund the qualified pension plans. The contribution to the other postretirement benefit plans' trust is generally based on the amount of the other postretirement benefit plans' periodic benefit cost for accounting purposes and is provided for in agreements with state regulatory authorities.

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

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2007	$ 345	$ 113	$ (9)
2008	354	121	(10)
2009	361	130	(11)
2010	366	139	(11)
2011	367	149	(12)
Years 2012 to 2016, in Total	1,821	839	(77)

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for fiscal years 2006, 2005 and 2004:

	Pension Plans			Other Postretirement Benefit Plans		
	2006	2005	2004	2006	2005	2004
			(in millions)			
Service Cost	$ 97	$ 93	$ 86	$ 39	$ 42	$ 41
Interest Cost	231	228	228	102	107	117
Expected Return on Plan Assets	(335)	(314)	(292)	(94)	(92)	(81)
Amortization of Transition Obligation	-	-	2	27	27	28
Amortization of Prior Service Cost (Credit)	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	79	55	17	22	25	36
Net Periodic Benefit Cost	71	61	40	96	109	141
Capitalized Portion	(21)	(17)	(10)	(27)	(33)	(46)
Net Periodic Benefit Cost Recognized as Expense	$ 50	$ 44	$ 30	$ 69	$ 76	$ 95

Estimated amounts expected to be amortized to net periodic benefit costs from pretax accumulated other comprehensive income during 2007 are shown in the following table:

	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 52	$ 15
Prior Service Cost (Credit)	(1)	-
Transition Obligation	-	27
Total Estimated 2007 Pretax AOCI Amortization	$ 51	$ 42

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2006	2005	2004	2006	2005	2004
			(in percentages)			
Discount Rate	5.50	5.50	6.25	5.65	5.80	6.25
Expected Return on Plan Assets	8.50	8.75	8.75	8.00	8.37	8.35
Rate of Compensation Increase	5.90	3.70	3.70	N/A	N/A	N/A

The expected return on plan assets for 2006 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, and current prospects for economic growth.

The health care trend rate assumptions as of January 1, used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates:	2006	2005
Initial	8.0 %	9.0 %
Ultimate	5.0 %	5.0 %
Year Ultimate Reached	2009	2009

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 19	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	193	(161)

AEP Savings Plans

We sponsor various defined contribution retirement savings plans for substantially all employees who are not members of the United Mine Workers of America (UMWA). These plans offer participants an opportunity to contribute a portion of their pay, include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. Our matching contributions to the plan are 75% of the first 6% of eligible compensation contributed by the employee. The cost for contributions to these plans totaled $62 million in 2006, $57 million in 2005 and $55 million in 2004.

UMWA Benefits

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

The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2006, 2005 and 2004.

10. NUCLEAR

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. A significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plant results from its ownership. Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial. By agreement, I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranges from $733 million to $1.3 billion in 2006 nondiscounted dollars. The wide range is caused by variables in assumptions. I&M recovers estimated Cook Plant decommissioning costs in its rates. The amount recovered in rates for decommissioning the Cook Plant was $30 million in 2006 and $27 million in 2005 and 2004. Decommissioning costs recovered from customers are deposited in external trusts.

I&M deposited an additional $4 million in 2006, 2005 and 2004 in its decommissioning trust for Cook Plant under funding provisions approved by regulatory commissions. At December 31, 2006, the total decommissioning trust fund balance for the Cook Plant was $974 million. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. Decommissioning costs for the Cook Plant including interest, unrealized gains and losses and expenses of the trust funds increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2006, fees and related interest of $247 million for fuel consumed prior to April 7, 1983 at the Cook Plant have been recorded as Long-term Debt and funds collected from customers towards payment of the pre-April 1983 fee and related earnings of $274 million are recorded as part of Spent Nuclear Fuel and Decommissioning Trust on our Consolidated Balance Sheets. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

Trust Assets for Decommissioning and SNF Disposal

We record securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel at market value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. As discussed in the "Nuclear Trust Funds" section of Note 1, we record unrealized gains and losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. The gains, losses or other-than-temporary impairments shown below did not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdictions' liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of nuclear trust fund investments at December 31:

	December 31, 2006			December 31, 2005		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Gross Unrealized Losses
			(in millions)			
Cash	$ 24	$ -	$ -	$ 21	$ -	$ -
Debt Securities	750	18	(8)	691	7	(7)
Equity Securities	474	192	(4)	422	148	(3)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,248	$ 210	$ (12)	$ 1,134	$ 155	$ (10)

Proceeds from sales of nuclear trust fund investments were $631 million, $706 million and $950 million in 2006, 2005 and 2004, respectively. Purchases of nuclear trust fund investments were $692 million, $761 million and $1,001 million in 2006, 2005 and 2004, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $7 million, $13 million and $13 million in 2006, 2005 and 2004, respectively. Gross realized losses including other-than-temporary impairments in 2006 from the sales of nuclear trust fund investments were $7 million, $17 million and $18 million in 2006, 2005 and 2004, respectively.

The fair value of debt securities, summarized by contractual maturities, at December 31, 2006 is as follows:

		Fair Value of Debt Securities
		(in millions)
Within 1 year	$	50
1 year – 5 years		188
5 years – 10 years		215
After 10 years		297
Total	$	750

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $38 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $10.8 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $15 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $30 million. The number of incidents for which payments could be required is not limited. Under an industry-wide program insuring workers at nuclear facilities, I&M is also obligated for assessments of up to $6 million for potential claims until December 31, 2007.

In the event of an incident of a catastrophic nature, we are initially covered for the first $300 million through commercially available insurance. The next level of liability coverage of up to $10.8 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and under the Price-Anderson Act, we would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition could be adversely affected.

11. BUSINESS SEGMENTS

Our primary business strategy and the core of our business focus on our electric utility operations. Within our Utility Operations segment, we centrally dispatch all generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Generation/supply in Ohio and Virginia continue to have commission-determined transition rates. Virginia is currently considering returning to regulation for generation. While our Utility Operations segment remains our primary business segment, the emergence of other areas of our business prompted us to identify two new business segments in 2006. One of these new segments is our MEMCO Operations segment, which reflects our significant ongoing barging activities. We also identified our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities in the ERCOT market area. We no longer consider Investments – Gas Operations and Investments – UK Operations as reportable segments because we have sold substantially all of those assets.

Starting in the fourth quarter of 2006, our new segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

MEMCO Operations

- Bulk commodity barging operations.

Generation and Marketing

- IPPs, wind farms and marketing and risk management activities in ERCOT.

The remainder of our company's activities is presented as All Other. While not considered a business segment, All Other includes:

- Parent company's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Our UK operations, which were sold in 2004.
- Our gas pipeline and storage operations, which were sold in 2004 and 2005.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility.

The tables below present our reportable segment information for the years ended December 31, 2006, 2005 and 2004 and balance sheet information as of December 31, 2006 and 2005. These amounts include certain estimates and allocations where necessary. We reclassified prior year amounts to conform to the current year's presentation.

		Nonutility Operations				
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)		
Year Ended December 31, 2006						
Revenues from:						
External Customers	$ 12,066	$ 520	$ 62	$ (26)	$ -	$ 12,622
Other Operating Segments	(55)	12	-	97	(54)	-
Total Revenues	$ 12,011	$ 532	$ 62	$ 71	$ (54)	$ 12,622
Depreciation and Amortization	$ 1,435	$ 11	$ 17	$ 4	$ -	$ 1,467
Interest Income	36	-	2	91	(68)	61
Interest Expense	667	4	11	118	(68)	732
Income Tax Expense (Credit)	543	42	(19)	(81)	-	485
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,028	$ 80	$ 12	$ (128)	$ -	$ 992
Discontinued Operations, Net of Tax	-	-	-	10	-	10
Net Income (Loss)	$ 1,028	$ 80	$ 12	$ (118)	$ -	$ 1,002
Gross Property Additions	$ 3,494	$ 7	$ 1	$ 26(b)	$ -	$ 3,528

Year Ended December 31, 2005	Utility Operations	Nonutility Operations: MEMCO Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 11,157	$ 344	$ 73	$ 537	$ -	$ 12,111
Other Operating Segments	232	11	-	(174)	(69)	-
Total Revenues	$ 11,389	$ 355	$ 73	$ 363	$ (69)	$ 12,111
Depreciation and Amortization	$ 1,315	$ 11	$ 17	$ 5	$ -	$ 1,348
Interest Income	31	-	2	80	(54)	59
Interest Expense	588	3	16	144	(54)	697
Income Tax Expense (Credit)	475	10	(28)	(27)	-	430
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,018	$ 21	$ 16	$ (26)	$ -	$ 1,029
Discontinued Operations, Net of Tax	-	-	-	27	-	27
Extraordinary Loss, Net of Tax	(225)	-	-	-	-	(225)
Cumulative Effect of Accounting Changes, Net of Tax	(17)	-	-	-	-	(17)
Net Income	$ 776	$ 21	$ 16	$ 1	$ -	$ 814
Gross Property Additions	$ 2,755	$ 7	$ -	$ 2	$ -	$ 2,764

Year Ended December 31, 2004	Utility Operations	Nonutility Operations: MEMCO Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 10,620	272	90	3,263	-	14,245
Other Operating Segments	144	11	3	55	(213)	-
Total Revenues	$ 10,764	$ 283	$ 93	$ 3,318	$ (213)	$ 14,245
Depreciation and Amortization	$ 1,281	$ 11	$ 18	$ 14	$ -	$ 1,324
Interest Income	16	1	3	52	(39)	33
Interest Expense	621	3	15	181	(39)	781
Income Tax Expense (Credit)	558	5	18	(9)	-	572
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,175	$ 12	$ 73	$ (133)	$ -	$ 1,127
Discontinued Operations, Net of Tax	-	-	-	83	-	83
Extraordinary Loss, Net of Tax	(121)	-	-	-	-	(121)
Net Income (Loss)	$ 1,054	$ 12	$ 73	$ (50)	$ -	$ 1,089
Gross Property Additions	$ 1,471	$ 5	$ -	$ 161	$ -	$ 1,637

	Utility Operations	MEMCO Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling Adjustments (c)	Consolidated
				(in millions)		
As of December 31, 2006						
Total Property, Plant and Equipment	$ 41,420	$ 239	$ 327	$ 35	$ -	$ 42,021
Accumulated Depreciation and Amortization	15,101	51	83	5	-	15,240
Total Property, Plant and Equipment – Net	$ 26,319	$ 188	$ 244	$ 30	$ -	$ 26,781
Total Assets	$ 36,632	$ 315	$ 342	$ 11,460	$ (10,762)	$ 37,987
Assets Held for Sale	44	-	-	-	-	44
Investments in Equity Method Subsidiaries	-	-	42	-	-	42
As of December 31, 2005						
Total Property, Plant and Equipment	$ 38,283	$ 233	$ 327	$ 278	$ -	$ 39,121
Accumulated Depreciation and Amortization	14,723	41	66	7	-	14,837
Total Property, Plant and Equipment – Net	$ 23,560	$ 192	$ 261	$ 271	$ -	$ 24,284
Total Assets	$ 34,344	$ 297	$ 396	$ 12,672	$ (11,537)	$ 36,172
Assets Held for Sale	44	-	-	-	-	44
Investments in Equity Method Subsidiaries	-	-	40	12	-	52

(a) All Other includes:
- Parent company's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Our UK operations, which were sold in 2004.
- Our gas pipeline and storage operations, which were sold in 2004 and 2005.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility.

(b) Gross Property Additions for All Other includes the $25 million acquisition of turbines by one of our nonregulated, wholly-owned subsidiaries. These turbines will be refurbished and transferred to a generating facility within our Utility Operations segment by the second half of 2008.

(c) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

12. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. Because energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized on the accrual or settlement basis.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Consolidated Statements of Income depending on the relevant facts and circumstances.

Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in earnings during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets until the period the hedged item affects earnings. We recognize any hedge ineffectiveness in earnings immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Fair Value Hedging Strategies

Prior to the sale of HPL in the first quarter of 2005, to hedge the risks associated with our domestic gas pipeline and storage activities, we entered into natural gas derivative transactions to hedge natural gas inventory. The purpose of this hedging activity was to protect the natural gas inventory against changes in fair value due to changes in spot gas prices. The derivative transactions designated as fair value hedges of our natural gas inventory were MTM each month based upon changes in the NYMEX forward prices, whereas the natural gas inventory was MTM on a monthly basis based upon changes in the Gas Daily spot price at the end of the month. The differences between the indices used to MTM the natural gas inventory and the derivative transactions designated as fair value hedges can result in volatility in our reported net income. However, over time gains or losses on the sale of the natural gas inventory will be offset by gains or losses on the fair value hedges, resulting in the realization of gross margin we anticipated at the time the transaction was structured. In the third quarter of 2004, the gas-related fair value hedges were de-designated. As a result, the existing hedged inventory was held at the market price on the fair value hedge de-designation date with subsequent additions to inventory carried at cost. As a result of the sale of HPL in 2005, we no longer employ this risk management strategy. During 2005 and 2004, we recognized a pretax loss of zero and approximately $27 million, respectively, in Revenues on our Consolidated Statements of Income related to hedge ineffectiveness and changes in time value excluded from the assessment of hedge ineffectiveness.

We enter into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. We record gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged, in Interest Expense on our Consolidated Statements of Income. During 2006, 2005 and 2004, we recognized no hedge ineffectiveness related to these derivative transactions.

Cash Flow Hedging Strategies

At times we are exposed to foreign currency exchange rate risks primarily because we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The accumulated gains or losses related to our foreign currency hedges, which are immaterial, are reclassified from Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets into Operating Expenses on our Consolidated Statements of Income over the same period as the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. We do not hedge all foreign currency exposure.

We enter into interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. We reclassify gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2006 and 2005, we reclassified immaterial amounts into earnings due to hedge ineffectiveness. During 2004, we reclassified an immaterial amount to earnings because the original forecasted transaction did not occur within the originally specified time period.

We enter into, and designate as cash flow hedges, certain derivative transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues or Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to energy commodities. During 2006, 2005 and 2004, we recognized immaterial amounts in earnings related to hedge ineffectiveness.

We entered into natural gas futures contracts to protect against the reduction in value of forecasted cash flows resulting from spot purchases and sales of natural gas at Houston Ship Channel (HSC). Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues. As a result of the sale of HPL in 2005, we no longer employ this risk management strategy. During 2005 and 2004, we recognized immaterial amounts in earnings related to hedge ineffectiveness.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2006 are:

	Hedging Assets (a)	Hedging Liabilities (a)	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings During the Next Twelve Months
		(in millions)		
Power	$ 30	$ (4)	$ 17	$ 17
Interest Rate	4	(4)	(23) (b)	(2)
Total	$ 34	$ (8)	$ (6)	$ 15

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheet.
(b) Includes $1 million loss recorded in an equity investment.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2005 are:

	Hedging Assets (a)	Hedging Liabilities (a)	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings During the Next Twelve Months
		(in millions)		
Power and Gas	$ 11	$ 20	$ (6)	$ (5)
Interest Rate	3	-	(21) (b)	(2)
Total	$ 14	$ 20	$ (27)	$ (7)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheet.
(b) Includes $1 million loss recorded in an equity investment.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of December 31, 2006, the maximum length of time that we are hedging, with SFAS 133 designated contracts, our exposure to variability in future cash flows related to forecasted transactions is forty-two-months.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2006:

	Amount (in millions)
Balance at December 31, 2003	$ (94)
Changes in fair value	8
Reclasses from AOCI to net earnings	86
Balance at December 31, 2004	-
Changes in fair value	(5)
Reclasses from AOCI to net earnings	(22)
Balance, at December 31, 2005	(27)
Changes in fair value	13
Reclasses from AOCI to net earnings	8
Balance at December 31, 2006	$ (6)

FINANCIAL INSTRUMENTS

The fair value of Long-term Debt is based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of significant financial instruments at December 31, 2006 and 2005 are summarized in the following tables.

	2006		2005	
	Book Value	Fair Value	Book Value	Fair Value
		(in millions)		
Long-term Debt	$ 13,698	$ 13,743	$ 12,226	$ 12,416

13. INCOME TAXES

The details of our consolidated income taxes before discontinued operations, extraordinary loss and cumulative effect of accounting change as reported are as follows:

	Year Ended December 31, 2006	2005 (in millions)	2004
Federal:			
Current	$ 429	$ 375	$ 262
Deferred	5	28	263
Total	434	403	525
State and Local:			
Current	61	25	49
Deferred	(10)	4	(3)
Total	51	29	46
International:			
Current	-	(2)	1
Deferred	-	-	-
Total	-	(2)	1
Total Income Tax Expense Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 485	$ 430	$ 572

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

	Year Ended December 31, 2006	2005 (in millions)	2004
Net Income	$ 1,002	$ 814	$ 1,089
Discontinued Operations (net of income tax of $(1) million, $(30) million and $75 million in 2006, 2005 and 2004, respectively)	(10)	(27)	(83)
Extraordinary Loss, (net of income tax of $(121) million and $(64) million in 2005 and 2004, respectively)	-	225	121
Cumulative Effect of Accounting Change (net of income tax of $(9) million in 2005)	-	17	-
Preferred Stock Dividends	3	7	6
Income Before Preferred Stock Dividends of Subsidiaries	995	1,036	1,133
Income Tax Expense Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	485	430	572
Pretax Income	$ 1,480	$ 1,466	$ 1,705
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 518	$ 513	$ 597
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	38	39	36
Investment Tax Credits, Net	(29)	(32)	(29)
Tax Effects of International Operations	-	(2)	1
Energy Production Credits	(19)	(18)	(16)
State Income Taxes	33	19	30
Removal Costs	(15)	(14)	(12)
AFUDC	(18)	(14)	(11)
Medicare Subsidy	(12)	(13)	(10)
Tax Reserve Adjustments	9	(11)	(14)
Other	(20)	(37)	-
Total Income Tax Expense Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 485	$ 430	$ 572
Effective Income Tax Rate	32.8%	29.3%	33.5%

The following table shows elements of the net deferred tax liability and significant temporary differences.

	As of December 31, 2006	2005
	(in millions)	
Deferred Tax Assets	$ 2,384	$ 2,085
Deferred Tax Liabilities	(7,074)	(6,895)
Net Deferred Tax Liabilities	$ (4,690)	$ (4,810)
Property Related Temporary Differences	$ (3,292)	$ (3,301)
Amounts Due From Customers For Future Federal Income Taxes	(193)	(186)
Deferred State Income Taxes	(318)	(384)
Transition Regulatory Assets	(46)	(176)
Securitized Transition Assets	(809)	(232)
Regulatory Assets	(334)	(492)
Accrued Pensions	(155)	(345)
Deferred Income Taxes on Other Comprehensive Loss	120	14
All Other, Net	337	292
Net Deferred Tax Liabilities	$ (4,690)	$ (4,810)

We join in the filing of a consolidated federal income tax return with our affiliated companies in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current expense. The tax benefit of the Parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The IRS and other taxing authorities routinely examine our tax returns. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for years prior to 1997. We have reached a negotiated settlement of all outstanding proposed IRS adjustments for years 1997 through 1999 and through June 2000 for the CSW pre-merger tax period and anticipate payment for the agreed adjustments to occur during 2007. Returns for the years 2000 through 2003 are presently being audited by the IRS.

Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As of December 31, 2006, we have total provisions for uncertain tax positions of approximately $32 million. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. We announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. We filed applications for the Mountaineer and Great Bend projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was awarded credits during this round of credit awards. We will continue to pursue credits for the next round of credits in 2009.

The Energy Tax Incentives Act of 2005 also changed the tax depreciation life for transmission assets from 20 years to 15 years. This act also allows for the accelerated amortization of atmospheric pollution control equipment placed in service after April 11, 2005 and installed on plants placed in service on or after January 1, 1976. This provision allows for tax amortization of the equipment over eighty-four months in lieu of taking a depreciation deduction over twenty-years. This act also allows for the transfer ("poured-over") of funds held in nonqualifying nuclear decommissioning trusts into qualified nuclear decommissioning trusts. The tax deduction may be claimed, as the nonqualified funds are poured-over; the funds are poured-over during the remaining life of the plant. The earnings on funds held in a qualified nuclear decommissioning fund are taxed at a 20% federal rate as opposed to a 35% federal tax rate for nonqualified funds. The tax law changes discussed in this paragraph have not materially affected our results of operations, cash flows, or financial condition.

After Hurricanes Katrina, Rita and Wilma in 2005, a series of tax acts were placed into law to aid in the recovery of the Gulf coast region. The Katrina Emergency Tax Relief Act of 2005 (enacted September 23, 2005) and the Gulf Opportunity Zone Act of 2005 (enacted December 21, 2005) contained a number of provisions to aid businesses and individuals impacted by these hurricanes. The application of these tax acts has not materially affected our results of operations, cash flows, or financial condition.

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, we reversed deferred state income tax liabilities of $83 million that are not expected to reverse during the phase-out. We recorded $4 million as a reduction to Income Tax Expense and, for the Ohio companies, established a regulatory liability for $57 million pending rate-making treatment in Ohio. See "Ormet" section of Note 4 for further discussion. For those companies in which state income taxes flow through for rate-making purposes, the adjustments reduced the regulatory assets associated with the deferred state income tax liabilities by $22 million. In November 2006, the PUCO ordered that the $57 million be amortized to income as an offset to power supply contract losses incurred by CSPCo and OPCo for sales to Ormet.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. The increase in Taxes Other than Income Taxes was approximately $4 million and $2 million for 2006 and 2005, respectively.

In the second quarter of 2006, the Texas state legislature replaced the existing franchise/income tax with a gross margin tax at a 1% rate for electric utilities. Overall, the new law reduces Texas income tax rates and is effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109. Based on the new law, we reviewed deferred tax liabilities with consideration given to the rate changes and changes to the allowed deductible items with temporary differences. As a result, in the second quarter of 2006, we recorded a net reduction to Deferred Income Taxes on our Consolidated Balance Sheet of $48 million of which $2 million was credited to Income Tax Expense and $46 million was credited to Regulatory Assets based upon the related rate-making treatment.

The Tax Increase Prevention and Reconciliation Act of 2005 (TIPRA 2005) was passed May 17, 2006. The majority of the provisions in TIPRA 2005 were directed toward individual income tax relief including the extension of reduced tax rates for dividends and capital gains through 2010. We believe the application of this act will not materially affect our results of operations, cash flows, or financial condition.

The President signed the Pension Protection Act of 2006 (PPA 2006) into law on August 17, 2006. This law is directed toward strengthening qualified retirement plans and adding new restrictions on charitable contributions. Specifically, PPA 2006 concentrates on the funding of defined benefit plans and the health of the Pension Benefit Guaranty Corporation. PPA 2006 imposes new minimum funding rules for multiemployer plans as well as increasing the deduction limitation for contributions to multiemployer defined benefit plans. Due to the significant funding of the AEP pension plans in 2005, the Act will not materially affect our results of operations, cash flows, or financial condition.

On December 20, 2006, the Tax Relief and Health Care Act of 2006 (TRHCA 2006) was signed into law. The primary purpose of the bill was to extend expiring tax provisions for individuals and business taxpayers and provide increased tax flexibility around medical benefits. In addition to extending the lower capital gains and dividend tax rates for individuals, TRHCA 2006 extended the research credit and for 2007 provides a new alternative formula for deterring the research credit. The application of TRHCA 2006 is not expected to materially affect our results of operations, cash flows or financial condition.

14. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Year Ended December 31,		
	2006	2005	2004
Lease Rental Costs	(in millions)		
Net Lease Expense on Operating Leases	$ 340	$ 298	$ 308
Amortization of Capital Leases	64	57	54
Interest on Capital Leases	17	13	11
Total Lease Rental Costs	$ 421	$ 368	$ 373

The following table shows the property, plant and equipment under capital leases and related obligations recorded on our Consolidated Balance Sheets. Capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on our Consolidated Balance Sheets.

	December 31,	
	2006	2005
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 94	$ 95
Distribution	15	15
Other	360	331
Construction Work in Progress	30	-
Total Property, Plant and Equipment Under Capital Leases	499	441
Accumulated Amortization	210	190
Net Property, Plant and Equipment Under Capital Leases	$ 289	$ 251
Obligations Under Capital Leases		
Noncurrent Liability	$ 210	$ 193
Liability Due Within One Year	81	58
Total Obligations Under Capital Leases	$ 291	$ 251

Future minimum lease payments consisted of the following at December 31, 2006:

	Capital Leases	Noncancelable Operating Leases
Future Minimum Lease Payments	(in millions)	
2007	$ 90	$ 331
2008	68	312
2009	49	287
2010	28	260
2011	15	230
Later Years	126	1,893
Total Future Minimum Lease Payments	$ 376	$ 3,313
Less Estimated Interest Element	85	
Estimated Present Value of Future Minimum Lease Payments	$ 291	

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale and leaseback transaction as of December 31, 2006 are as follows:

Future Minimum Lease Payments	AEGCo	I&M
	(in millions)	
2007	$ 74	$ 74
2008	74	74
2009	74	74
2010	74	74
2011	74	74
Later Years	812	812
Total Future Minimum Lease Payments	$ 1,182	$ 1,182

Railcar Lease

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years. At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years; (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value; or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. We intend to renew the lease for the full twenty years. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the current lease term from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2006, the maximum potential loss was approximately $31 million ($20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. We have other railcar lease arrangements that do not utilize this type of financing structure.

Sabine Dragline Lease

In December 2006, Sabine Mining Company (Sabine), an entity consolidated under FIN 46, entered into a capital lease agreement with a nonaffiliated company to finance the purchase of a $51 million electric dragline for Sabine's mining operations. The initial capital outlay for the dragline was $26 million with an additional estimated $25 million of transportation, assembly and upgrade costs to be incurred prior to the completion date of mid-2008. These additional costs will be added to our consolidated lease assets and capital lease obligations as they are incurred. Sabine will pay interim rent on a quarterly basis starting in March 2007 and continue through the completion date of mid-2008. Once the dragline is fully assembled, Sabine will pay capital and interest payments on the outstanding lease obligation. At December 31, 2006, the capital lease asset is included in Construction Work in Progress and the capital lease obligation is included in Noncurrent Liabilities – Deferred Credits and Other on our 2006 Consolidated Balance Sheet. We calculated future payments using both interim rent prior to completion and capital and interest from completion until the maturity of the lease solely using the initial capital outlay of $26 million.

15. FINANCING ACTIVITIES

Common Stock

Common Stock Repurchase

In February 2005, our Board of Directors authorized the repurchase of up to $500 million of our common stock from time to time through 2006. In March 2005, we purchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share plus transaction fees. The purchase of shares in the open market was completed by a broker-dealer in May 2005 and we received a purchase price adjustment of $6.45 million based on the actual cost of the shares repurchased. Based on this adjustment, our actual stock purchase price averaged $34.18 per share. Management has not established a timeline for the buyback of the remaining stock under this plan.

Equity Units and Remarketing of Senior Notes

In June 2002, AEP issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consisted of a forward purchase contract and a senior note. In June 2005, we remarketed and settled $345 million of our 5.75% senior notes at a new interest rate of 4.709%. The senior notes mature on August 16, 2007. We did not receive any proceeds from the mandatory remarketing.

Issuance of Common Stock

On August 16, 2005, we issued approximately 8.4 million shares of common stock in connection with the settlement of forward purchase contracts that formed a part of our outstanding 9.25% equity units. In exchange for $50 per equity unit, holders of the equity units received 1.2225 shares of AEP common stock for each purchase contract and cash in lieu of fractional shares. Each holder was not required to make any additional cash payment. The equity unit holder's purchase obligation was satisfied from the proceeds of a portfolio of U.S. Treasury securities held in a collateral account that matured on August 1, 2005. The portfolio of U.S. Treasury securities was acquired in connection with the June 2005 remarketing of the senior notes discussed above.

We issued 2.3 million, 1.9 million and 0.5 million shares of common stock in connection with our stock option plan during 2006, 2005 and 2004, respectively.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2006, 2005 and 2004:

Shares of Common Stock	Issued	Held in Treasury
Balance, January 1, 2004	404,016,413	8,999,992
Issued	841,732	-
Balance, December 31, 2004	404,858,145	8,999,992
Issued	10,360,685	-
Treasury Stock Acquisition	-	12,500,000
Balance, December 31, 2005	415,218,830	21,499,992
Issued	2,955,898	-
Balance, December 31, 2006	418,174,728	21,499,992

Preferred Stock

Information about the components of preferred stock of our subsidiaries is as follows:

	December 31, 2006			
	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (c)	Amount (in millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	607,044	$ 61

	December 31, 2005			
	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (c)	Amount (in millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	607,642	$ 61

(a) At the option of the subsidiary, the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares.
(b) As of December 31, 2006, the subsidiaries had 14,487,993 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,822,366 shares of no par value preferred stock that were authorized but unissued. As of December 31, 2005, the subsidiaries had 14,487,597 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,822,164 shares of no par value preferred stock that were authorized but unissued.
(c) The number of shares of preferred stock redeemed is 598 shares in 2006, 664,470 shares in 2005 and 96,378 shares in 2004.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate December 31, 2006	Interest Rate Range at December 31, 2006	2005	December 31, 2006	2005
				(in millions)	
SENIOR UNSECURED NOTES (a)					
2006-2011	5.11%	3.60%-6.91%	3.60%-6.91%	$ 3,085	$ 3,529
2012-2017	5.41%	4.85%-6.375%	4.85%-6.375%	2,793	2,568
2032-2037	6.20%	5.625%-6.65%	5.625%-6.65%	2,775	2,125
POLLUTION CONTROL BONDS (b)					
2006-2011	4.12%	3.60%-4.90%	2.70%-4.55%	181	204
2014-2024	4.28%	3.50%-6.05%	2.625%-6.10%	811	794
2025-2038	4.06%	3.53%-6.125%	2.625%-6.55%	958	937
NOTES PAYABLE (c)					
2006-2017	6.86%	4.47%-9.60%	4.47%-15.25%	337	904
SECURITIZATION BONDS (d)					
2008-2021	5.32%	4.98%-6.25%	5.01%-6.25%	2,335	648
FIRST MORTGAGE BONDS (e)					
2006-2008 (f)	7.07%	7.00%-7.75%	6.20%-7.75%	117	222
NOTES PAYABLE TO TRUST					
2043	5.25%	5.25%	5.25%	113	113
SPENT NUCLEAR FUEL OBLIGATION (g)				247	236
OTHER LONG-TERM DEBT (h)					
2026	13.718%	13.718%	13.718%	2	4
Unamortized Discount (net)				(56)	(58)
Total Long-term Debt Outstanding				13,698	12,226
Less Portion Due Within One Year				1,269	1,153
Long-term Portion				$ 12,429	$ 11,073

(a) Certain senior unsecured notes have been adjusted for MTM of Fair Value Hedges associated with the debt.
(b) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and standby bond purchase agreements support certain series.
(c) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(d) In October 2006, AEP Texas Central Transition Funding II LLC (TFII), a subsidiary of TCC, issued $1.7 billion in securitization bonds with interest rates ranging from 4.98% to 5.3063% and final maturity dates ranging from January 2012 to July 2021. Scheduled final payment dates range from January 2010 to July 2020. TFII is the sole owner of the transition charges and the original transition property. The holders of the securitization bonds do not have recourse to any assets or revenues of TCC. The creditors of TCC do not have recourse to any assets or revenues of TFII, including, without limitation, the original transition property.
(e) First mortgage bonds are secured by first mortgage liens on electric property, plant and equipment. There are certain limitations on establishing additional liens against our assets under our indentures.
(f) In May 2004, we deposited cash and treasury securities with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had balances of $19 million in 2006 and 2005. Trust fund assets related to this obligation of $2 million are included in Other Temporary Cash Investments and $21 million are included in Other Noncurrent Assets on our Consolidated Balance Sheets at December 31, 2006 and 2005. In December 2005, we deposited cash and treasury securities with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond has a balance of $8 million at December 31, 2006 and 2005. Trust fund assets related to this obligation of $9 million and $1 million at December 31, 2006 and 2005, respectively, are included in Other Temporary Cash Investments and $8 million is included in Other Noncurrent Assets on our Consolidated Balance Sheets at December 31, 2005. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.
(g) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 10).
(h) Other long-term debt consists of a financing obligation under a sale and leaseback agreement.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2006 IS PAYABLE AS FOLLOWS:

	2007	2008	2009	2010	2011	After 2011	Total
				(in millions)			
Principal Amount	$ 1,269	$ 650	$ 485	$ 1,315	$ 596	$ 9,439	$ 13,754
Unamortized Discount							(56)
Total Long-term Debt Outstanding at December 31, 2006							$ 13,698

Dividend Restrictions

Under the Federal Power Act, AEP's public utility subsidiaries can only pay dividends out of retained or current earnings unless they obtain prior FERC approval.

Trust Preferred Securities

SWEPCo has a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46. The SWEPCo trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on our Consolidated Balance Sheets. The investment in the trust, which was $3 million as of December 31, 2006 and 2005, is included in Deferred Charges and Other within Other Noncurrent Assets. The Junior Subordinated Debentures, in the amount of $113 million as of December 31, 2006 and 2005, are reported as Notes Payable to Trust within Long-term Debt.

The business trust is treated as a nonconsolidated subsidiary of SWEPCo. The only asset of the business trust is the subordinated debentures issued by SWEPCo as specified above. In addition to the obligations under the subordinated debentures, SWEPCo also agreed to a security obligation, which represents a full and unconditional guarantee of its capital trust obligation.

Lines of Credit and Short-term Debt – AEP System

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2006, we had credit facilities totaling $3 billion to support our commercial paper program. As of December 31, 2006, AEP's commercial paper outstanding related to the corporate borrowing program was $0. For the corporate borrowing program the maximum amount of commercial paper outstanding during the year was $325 million in March 2006 and the weighted average interest rate of commercial paper outstanding during the year was 4.96%. Our outstanding short-term debt was as follows:

	December 31, 2006		December 31, 2005	
Type of Debt	Outstanding Amount (in millions)	Interest Rate	Outstanding Amount (in millions)	Interest Rate
Commercial Paper – JMG (a)	$ 1	5.56 %	$ 10	4.47 %
Line of Credit – Sabine	17	6.38 %	-	-
Total	$ 18		$ 10	

(a) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility. This commercial paper does not reduce our available liquidity.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. We have no ownership interest in the commercial paper conduits and are not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. We entered into this off-balance sheet transaction to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables, and accelerate AEP Credit's cash collections.

AEP Credit's sale of receivables agreement expires on August 24, 2007. We intend to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2006, $536 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent receivables purchased by AEP Credit from certain Registrant Subsidiaries. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit also purchases accounts receivable from KGPCo.

Comparative accounts receivable information for AEP Credit is as follows:

	Year Ended December 31,		
	2006	**2005**	**2004**
		($ in millions)	
Proceeds from Sale of Accounts Receivable	$ 6,849	$ 5,925	$ 5,163
Loss on Sale of Accounts Receivable	$ 31	$ 18	$ 7
Average Variable Discount Rate	5.02%	3.23%	1.50%

	December 31,	
	2006	**2005**
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 87	$ 106
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	85	103
Retained Interest if 20% Adverse Change in Uncollectible Accounts	83	101

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	December 31, 2006	December 31, 2005
	(in millions)	
Customer Accounts Receivable Retained	$ 676	$ 826
Accrued Unbilled Revenues Retained	350	374
Miscellaneous Accounts Receivable Retained	44	51
Allowance for Uncollectible Accounts Retained	(30)	(31)
Total Net Balance Sheet Accounts Receivable	1,040	1,220
Customer Accounts Receivable Securitized	536	516
Total Accounts Receivable Managed	$ 1,576	$ 1,736
Net Uncollectible Accounts Written Off	$ 31	$ 74

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $29 million and $30 million at December 31, 2006 and 2005, respectively. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

16. STOCK-BASED COMPENSATION

As previously approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 19,200,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. A maximum of 9,000,000 shares may be used under this plan for full value shares awards, which include performance units, restricted shares and restricted stock units. The Board of Directors and shareholders both adopted the original LTIP in 2000 and the amended and restated version in 2005. We have not granted options as part of our regular stock-based compensation program since 2003. However, we have used options in limited circumstances totaling 149,000 options in 2004, 10,000 options in 2005 and none during 2006. The following sections provide further information regarding each type of stock-based compensation award granted by the Board of Directors.

We adopted SFAS 123R, effective January 1, 2006. See the SFAS 123 (revised 2004) "Share-Based Payment (SFAS 123R)" section of Note 2 for additional information.

Stock Options

For all stock options granted, the exercise price equaled or exceeded the market price of AEP's common stock on the date of grant. Stock options were granted with a ten-year term and generally vested, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. Compensation cost for stock options is recorded over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, we converted all CSW stock options outstanding into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. We adjusted the exercise price for each CSW stock option for the exchange ratio. No CSW stock options remained outstanding as of December 31, 2006. The remaining stock options were exercised in the fourth quarter of 2006.

The total fair value of stock options vested and the total intrinsic value of options exercised during the years ended December 31, 2006, 2005 and 2004 are as follows:

Stock Options	2006	2005	2004
	(in thousands)		
Fair Value of Stock Options Vested	$ 3,667	$ 5,036	$ 14,504
Intrinsic Value of Options Exercised (a)	16,823	12,091	3,182

(a) Intrinsic value is calculated as market price at exercise date less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2006, 2005 and 2004 is as follows:

	2006		2005		2004	
	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price
Outstanding at January 1,	6,222	$ 34.16	8,230	$ 33.29	9,095	$ 33.03
Granted	-	N/A	10	38.65	149	30.76
Exercised/Converted	(2,343)	33.12	(1,886)	36.94	(525)	27.10
Forfeited/Expired	(209)	41.58	(132)	31.97	(489)	34.33
Outstanding at December 31,	3,670	34.41	6,222	34.16	8,230	33.29
Options Exercisable at December 31,	3,411	$ 34.83	5,199	$ 35.40	6,069	$ 35.05
Weighted average exercise price of options:						
Granted above Market Price		N/A		N/A		N/A
Granted at Market Price		N/A		$ 38.65		$ 30.76

The following table summarizes information about AEP stock options outstanding at December 31, 2006.

Options Outstanding

2006 Range of Exercise Prices	Number Outstanding (in thousands)	Weighted Average Remaining Life (in years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$25.73 - $27.95	902	6.07	$ 27.45	$ 13,651
$30.76 - $38.65	2,401	3.29	35.34	17,392
$43.79 - $49.00	367	4.39	45.43	-
Total (a)	3,670	4.08	34.41	$ 31,043

(a) Options outstanding are not significantly different from the number of shares expected to vest.

The following table summarizes information about AEP stock options exercisable at December 31, 2006.

Options Exercisable

2006 Range of Exercise Prices	Number Exercisable (in thousands)	Weighted Average Remaining Life (in years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$25.73 - $27.95	702	5.83	$ 27.32	$ 10,715
$30.76 - $35.63	2,342	3.19	35.42	16,766
$43.79 - $49.00	367	4.39	45.43	-
Total	3,411	3.86	34.83	$ 27,481

We include the proceeds received from exercised stock options in common stock and paid-in capital. For options granted through December 31, 2006, we estimated the grant date fair value of each option award using a Black-Scholes option-pricing model with weighted average assumptions. We estimated expected volatilities using the historical monthly volatility of our common stock for the thirty-six-month period prior to each grant. We also assumed a seven-year average expected term. The risk-free rate is the yield for U.S. Treasury securities with a remaining life equal to the expected seven-year term of AEP stock options on the grant date.

We used the following weighted average assumptions to estimate the fair value of AEP stock options granted in 2005 and 2004. No stock options were granted in 2006.

	2006	2005	2004
Risk Free Interest Rate	N/A	4.14%	4.14%
Expected Volatility	N/A	24.63%	28.17%
Expected Dividend Yield	N/A	4.00%	4.84%
Expected Life	N/A	7 years	7 years
Weighted average fair value of options:			
Granted above Market Price	N/A	N/A	N/A
Granted at Market Price	N/A	$ 7.60	$ 6.06

Performance Units

Our performance units are equal in value to an equivalent number of shares of AEP common stock. The number of performance units held is multiplied by a performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measure(s) established for each grant at the beginning of the performance period by the Human Resources Committee of the Board of Directors (HR Committee) and can range from 0 percent to 200 percent. Performance units are typically paid in cash at the end of a three-year performance and vesting period, unless they are needed to satisfy a participant's stock ownership requirement, in which case they are mandatorily deferred as AEP Career Shares, a form of phantom stock units, until after the end of the participant's AEP career. AEP Career Shares have a value equivalent to the market value of an equal number of AEP common shares and are generally paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. The compensation cost for performance units is recorded over the vesting period and the liability, recorded in Employee Benefits and Pension Obligations on our Consolidated Balance Sheets, for both the performance units and AEP Career Shares is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation. The vesting period of all performance units is three years.

Our Board of Directors awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2006, 2005 and 2004 as follows:

	Year Ended December 31,		
	2006	2005	2004
Performance Units			
Awarded Units (in thousands)	1,635	1,013	119
Weighted Average Unit Fair Value at Grant Date	$ 39.75	$ 34.02 (a)	$ 30.76 (a)
Vesting Period (years)	3	3	3

(a) The unit fair value is the actual value at the grant date because there was only one award in that period.

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Year Ended December 31, 2006	2005	2004
Awarded Units (in thousands)	118	89	61
Weighted Average Grant Date Fair Value	$ 36.87	$ 36.25	$ 32.92
Vesting Period (years)	(a)	(a)	(a)

(a) Vesting Period (years) range from 0 to 3 years. The Vesting Period of the reinvested dividends is equal to the remaining life of the related performance units and AEP Career Shares.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures. The HR Committee has discretion to reduce or eliminate the value of final awards, but may not increase them. The performance scores for all open performance periods are dependent on two equally-weighted performance measures: three-year total shareholder return measured relative to the S&P Utilities Index and three-year cumulative earnings per share measured relative to a board-approved target. The value of each performance unit earned equals the average closing price of AEP common stock for the last 20 days of the performance period. In January 2006, the HR Committee certified a performance score for the three-year period ended December 31, 2005 of 49%. As a result, 108,486 performance units were earned. Of this amount 33,296 were mandatorily deferred as AEP Career Shares, 4,360 were voluntarily deferred into the Incentive Compensation Deferral Program and the remainder were paid in cash. The certified performance score for the three-year performance period ended December 31, 2004 was 0%.

Due to the anticipated 2004 CEO succession, on December 10, 2003 the HR Committee made performance unit grants for the shortened performance period of December 10, 2003 through December 31, 2004. No performance period ended on December 31, 2006 because this performance period was shorter than the normal three-year period used by us and there were no other performance unit grants in 2003. In 2005, the HR Committee certified a performance factor of 123.1% for performance units granted on December 10, 2003 and 946,789 performance units were mandatorily deferred into AEP stock units, of which 917,032 units vested on December 31, 2006 and the remainder were forfeited due to participant terminations. These stock units have the same value, dividend rights, vesting and accounting treatment as the performance units that gave rise to them, except that they are no longer subject to performance measures.

The cash payouts for the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31, 2006	2005	2004
	(in thousands)		
Cash Payouts for Performance Units	$ 2,630	$ -	$ -
Cash Payouts for AEP Career Share Distributions	1,079	1,373	673

Restricted Shares and Restricted Stock Units

Our Board of Directors granted 300,000 restricted shares to the Chairman, President and CEO on January 2, 2004 upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005 and 50,000 vested on January 1, 2006. The remaining 200,000 restricted shares vest, subject to his continued employment, in approximately equal thirds on November 30, 2009, 2010 and 2011. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market price of $30.76. The maximum term for these restricted shares is eight years. The Board of Directors has not granted other restricted shares. Dividends on our restricted shares are paid in cash.

Our Board of Directors may also grant restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments on the anniversaries of the grant date. Amounts equivalent to dividends paid on RSUs accrue as additional RSUs and vest on the last vesting date associated with the underlying units. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market price. The maximum contractual term of RSUs is six years.

In January 2006, our Board of Directors also granted RSUs with performance vesting conditions to certain employees who are integral to our project to design and build proposed IGCC power plants. Twenty percent of these awards vest on each of the first three anniversaries of the grant date. An additional 20% vest on the date the IGCC plant achieves commercial operations. The remaining 20% vest one year after the IGCC plant achieves commercial operations, subject to achievement of plant availability targets.

Our Board of Directors awarded RSUs, including units awarded for dividends, for the years ended December 31, 2006, 2005 and 2004 as follows:

	Year Ended December 31,		
Restricted Stock Units	**2006**	**2005**	**2004**
Awarded Units (in thousands)	65	166	106
Weighted Average Grant Date Fair Value	$ 37.47	$ 35.67	$ 32.03

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31,		
	2006	**2005**	**2004**
Restricted Shares and Restricted Stock Units	**(in thousands)**		
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 3,939	$ 3,087	$ 577
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	4,686	3,703	809

(a) Intrinsic value is calculated as market price.

A summary of the status of our nonvested restricted shares and RSUs as of December 31, 2006, and changes during the year ended December 31, 2006 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	**Shares/Units**	**Weighted Average Grant Date Fair Value**
	(in thousands)	
Nonvested at January 1, 2006	497	$ 32.19
Granted	65	37.47
Vested	(129)	30.63
Forfeited	(25)	35.72
Nonvested at December 31, 2006	408	33.31

The total aggregate intrinsic value of nonvested restricted shares and RSUs as of December 31, 2006 was $17 million and the weighted average remaining contractual life was 2.74 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-Employee Directors providing each nonemployee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The Non-Employee Directors vest immediately upon award of the stock units. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the 20 trading days immediately preceding the payment date.

The compensation cost for stock units is recorded when the units are awarded, and the liability is adjusted for changes in value based on the current 20-day average closing price of AEP common stock at the date of valuation.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2006, 2005 and 2004.

Our Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2006, 2005 and 2004 as follows:

	Year Ended December 31,		
	2006	2005	2004
Stock Unit Accumulation Plan for Non-Employee Directors			
Awarded Units (in thousands)	33	27	30
Weighted Average Grant Date Fair Value	$ 36.66	$ 36.74	$ 32.81

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31,		
	2006	2005	2004
Share-based Compensation Plans	(in thousands)		
Compensation Cost for Share-based Payment Arrangements (a)	$ 45,842	$ 28,660	$ 19,721
Actual Tax Benefit Realized	16,045	10,031	6,902
Total Compensation Cost Capitalized	10,953	5,113	3,518

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance on our Consolidated Statements of Income.

During the years ended December 31, 2006, 2005 and 2004, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2006, there was $90 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the liability is revalued each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.64 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31,		
	2006	**2005**	**2004**
Share-based Compensation Plans	**(in thousands)**		
Cash received from stock options exercised	$ 77,534	$ 57,546	$ 14,250
Actual tax benefit realized for the tax deductions from stock options exercised	5,825	4,235	1,107

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although we do not currently anticipate any changes to this practice, we could use reacquired shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced, at the participant's election, to offset AEP's tax withholding obligation.

17. PROPERTY, PLANT AND EQUIPMENT

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

2006	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)		(%)	(in years)	(in millions)		(%)	(in years)
Production	$ 7,892	$ 4,437	2.6 – 3.8	30 - 121	$ 8,895	$ 3,886	2.57 – 9.15	20 - 121
Transmission	7,018	2,332	1.6 - 2.9	25 - 87	-	-	N.M.	N.M.
Distribution	11,338	3,121	3.0 - 4.0	11 - 75	-	-	N.M.	N.M.
CWIP	1,423	(41)	N.M.	N.M.	2,050	2	N.M.	N.M.
Other	2,400	1,067	6.7 – 11.5	24 - 55	1,005	436	N.M.	N.M.
Total	$ 30,071	$ 10,916			$ 11,950	$ 4,324		

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)		(%)	(in years)	(in millions)		(%)	(in years)
Production	$ 7,411	$ 4,166	2.7 - 3.8	30 - 120	$ 9,095	$ 4,019	2.6 - 3.3	20 - 120
Transmission	6,433	2,280	1.7 - 3.0	25 - 75	-	-	N.M.	N.M.
Distribution	10,702	3,085	3.1 - 4.1	10 - 75	-	-	N.M.	N.M.
CWIP	1,341	(14)	N.M.	N.M.	876	(3)	N.M.	N.M.
Other	2,266	992	5.1 - 16.0	N.M.	997	312	2.0 - 4.9	2 - 37
Total	$ 28,153	$ 10,509			$ 10,968	$ 4,328		

2004	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(%)	(in years)	(%)	(in years)
Production	2.7 - 3.8	30 - 120	2.6 - 3.9	20 - 120
Transmission	1.7 - 3.0	25 - 75	N.M.	N.M.
Distribution	3.2 - 4.1	10 - 75	N.M.	N.M.
Other	5.4 - 16.4	N.M.	2.0 – 14.2	0 - 50

N.M. = Not Meaningful

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs were $0.66, $0.66 and $0.65 per ton in 2006, 2005 and 2004, respectively.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred (see "Accounting for Asset Retirement Obligations (ARO)" section of this note).

Accounting for Asset Retirement Obligations (ARO)

We implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. ARO accounting is being followed for regulated and nonregulated property that has a legal obligation related to asset retirement. Upon settlement of an ARO, any difference between the ARO liability and actual costs is recognized as income or expense.

We adopted FIN 47 during the fourth quarter of 2005. FIN 47 interprets the application of SFAS 143, "Accounting for Asset Retirement Obligations." It clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

We completed a review of our FIN 47 conditional ARO during the fourth quarter of 2005 and concluded that we have legal liabilities for asbestos removal and disposal in general buildings and generating plants. In 2005, we recorded $55 million of conditional ARO in accordance with FIN 47. The cumulative effect of certain retirement costs for asbestos removal related to our regulated operations was generally charged to regulatory liability. Of the $55 million, we recorded an unfavorable cumulative effect of $26 million ($17 million, net of tax) for our nonregulated generation operations related to asbestos removal in the Utility Operations segment.

We have legal obligations for asbestos removal and for the retirement of certain ash ponds, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. As of December 31, 2006 and 2005, our ARO liability was $1,028 million and $946 million, respectively, and included $803 million and $731 million for nuclear decommissioning of the Cook Plant. As of December 31, 2006 and 2005, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $974 million and $870 million, respectively, relating to the Cook Plant and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets.

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

Pro forma net income and earnings per share are not presented for the year ended December 31, 2004 because the pro forma application of FIN 47 would result in pro forma net income and earnings per share not materially different from the actual amounts reported during those periods. As of December 31, 2004, the pro forma liability for conditional ARO which has been calculated as if FIN 47 had been adopted at the beginning of each period was $52 million.

The following is a reconciliation of the 2005 and 2006 aggregate carrying amounts of ARO:

	Carrying Amount of ARO (in millions)
ARO at January 1, 2005, Including Held for Sale	$ 1,076
Accretion Expense	63
Liabilities Incurred (a)	76
Liabilities Settled	(4)
Revisions in Cash Flow Estimates	(9)
Less ARO Liability for:	
South Texas Project (b)	(256)
ARO at December 31, 2005 (c)	946
Accretion Expense	63
Liabilities Incurred	9
Liabilities Settled	(20)
Revisions in Cash Flow Estimates	30
ARO at December 31, 2006 (d)	$ 1,028

(a) Includes $55 million of ARO relating to the adoption of FIN 47.
(b) The ARO related to nuclear decommissioning costs for TCC's share of STP was transferred to the buyer in connection with the May 2005 sale (see "Dispositions" section of Note 8).
(c) The current portion of our ARO, totaling $10 million, is included in Other in the Current Liabilities section of our 2005 Consolidated Balance Sheet.
(d) The current portion of our ARO, totaling $5 million is included in Other in the Current Liabilities section of our 2006 Consolidated Balance Sheet.

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

The amounts of AFUDC were $30.2 million, $20.9 million and $14.5 million in 2006, 2005 and 2004, respectively, and are included in Allowance For Equity Funds Used During Construction on our Consolidated Statements of Income. The amounts of interest capitalized and allowance for borrowed funds used during construction were $82.3 million, $35.6 million and $22.4 million in 2006, 2005 and 2004, respectively, and are included in Interest Expense on our Consolidated Statements of Income.

Jointly-owned Electric Utility Plant

We have generating units that are jointly-owned with nonaffiliated companies. We are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Income and the investments and accumulated depreciation are reflected in our Consolidated Balance Sheets under Property, Plant and Equipment as follows:

			Company's Share at December 31, 2006		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress (h)	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 16	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5	85	32	49
J.M. Stuart Generating Station (c)	Coal	26.0	284	102	128
Wm. H. Zimmer Generating Station (a)	Coal	25.4	751	5	302
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2	240	5	167
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0	97	2	57
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9	481	5	310
Oklaunion Generating Station (Unit No. 1) (f)	Coal	78.1	417	3	200
Transmission	N/A	(g)	63	-	42

			Company's Share at December 31, 2005		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress (h)	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 16	$ -	$ 7
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5	85	8	48
J.M. Stuart Generating Station (c)	Coal	26.0	266	35	121
Wm. H. Zimmer Generating Station (a)	Coal	25.4	749	2	280
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2	238	4	160
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0	94	2	55
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9	460	10	298
Oklaunion Generating Station (Unit No. 1) (f)	Coal	78.1	415	3	192
Transmission	N/A	(g)	63	1	41

(a) Operated by Duke Energy Corporation, a nonaffiliated company.
(b) Operated by CSPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Operated by Cleco Corporation, a nonaffiliated company.
(e) Operated by SWEPCo.
(f) TCC's 7.8% interest in Oklaunion Generating Station amounted to $40 million at December 31, 2006 and 2005. These amounts are included in Assets Held for Sale on our Consolidated Balance Sheets. Oklaunion Generating Station is operated by PSO.
(g) Varying percentages of ownership.
(h) Primarily relates to environmental upgrades, including the installation of flue gas desulfurization projects at Conesville Generating Station and J.M. Stuart Generating Station.

N/A = Not Applicable

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2006 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in millions – except per share amounts)			
Revenues	$ 3,108	$ 2,936	$ 3,594	$ 2,984
Operating Income	689	371	535	371
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	378	172	265	177
Net Income	381	175	265	181
Basic Earnings per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	0.96	0.44	0.67	0.45
Earnings per Share	0.97	0.44	0.67	0.46
Diluted Earnings per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes (e)	0.95	0.43	0.67	0.44
Earnings per Share	0.96	0.44	0.67	0.46

	2005 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in millions – except per share amounts)			
Revenues	$ 3,065	$ 2,819	$ 3,328	$ 2,899
Operating Income	660	455	624	188
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	354	218	365	92
Extraordinary Loss, Net of Tax (a)	-	-	-	(225)
Net Income (Loss)	355	221	387	(149)
Basic Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	0.90	0.57	0.94	0.23
Extraordinary Loss per Share (b)	-	-	-	(0.57)
Earnings (Loss) per Share	0.90	0.58	0.99	(0.38)
Diluted Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes (c)	0.90	0.57	0.94	0.23
Extraordinary Loss per Share (b)	-	-	-	(0.57)
Earnings (Loss) per Share (d)	0.90	0.58	0.99	(0.38)

(a) See "Extraordinary Items" section of Note 2 for a discussion of the extraordinary loss booked in the fourth quarter of 2005.

(b) Amounts for 2005 do not add to $(0.58) for Extraordinary Loss per Share due to differences between the weighted average number of shares outstanding for the fourth quarter of 2005 and the year 2005.

(c) Amounts for 2005 do not add to $2.63 for Diluted Earnings (Loss) per Share before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes due to rounding.

(d) Amounts for 2005 do not add to $2.08 for Diluted Earnings (Loss) per Share due to rounding.

(e) Amounts for the quarter ended December 31, 2006 do not add to $2.50 for Diluted Earnings (Loss) per Share Before Discontinued Operations due to rounding.