Appendix A to the
Proxy Statement

American Electric Power

2009 Annual Report

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

AMERICAN®
ELECTRIC
POWER

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GLOSSARY OF TERMS

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

Term	Meaning
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 electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Foundation	AEP charitable organization created in 2005 for charitable contributions in the communities in which AEP's subsidiaries operate.
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.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CO_2	Carbon Dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 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, as amended, by and among PSO and SWEPCo 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.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo that is a consolidated variable interest entity.
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.

Term	Meaning
ETA	Electric Transmission America, LLC an equity interest joint venture with MidAmerican Energy Holdings Company formed to own and operate electric transmission facilities in North America outside of ERCOT.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
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.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP's Nonutility Money Pool.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.

Term	Meaning
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO and SWEPCo.
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.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill 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.
TA	Transmission Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets.
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.
Turk Plant	John W. Turk, Jr. Plant.
Utility Money Pool	AEP System's Utility Money Pool.
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:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load and customer growth.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process.
- 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, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) 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 or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation (including our dispute with Bank of America).
- Our ability to constrain operation and maintenance costs.
- 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, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements.
- Prices and demand 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.

AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

AEP COMMON STOCK AND DIVIDEND INFORMATION

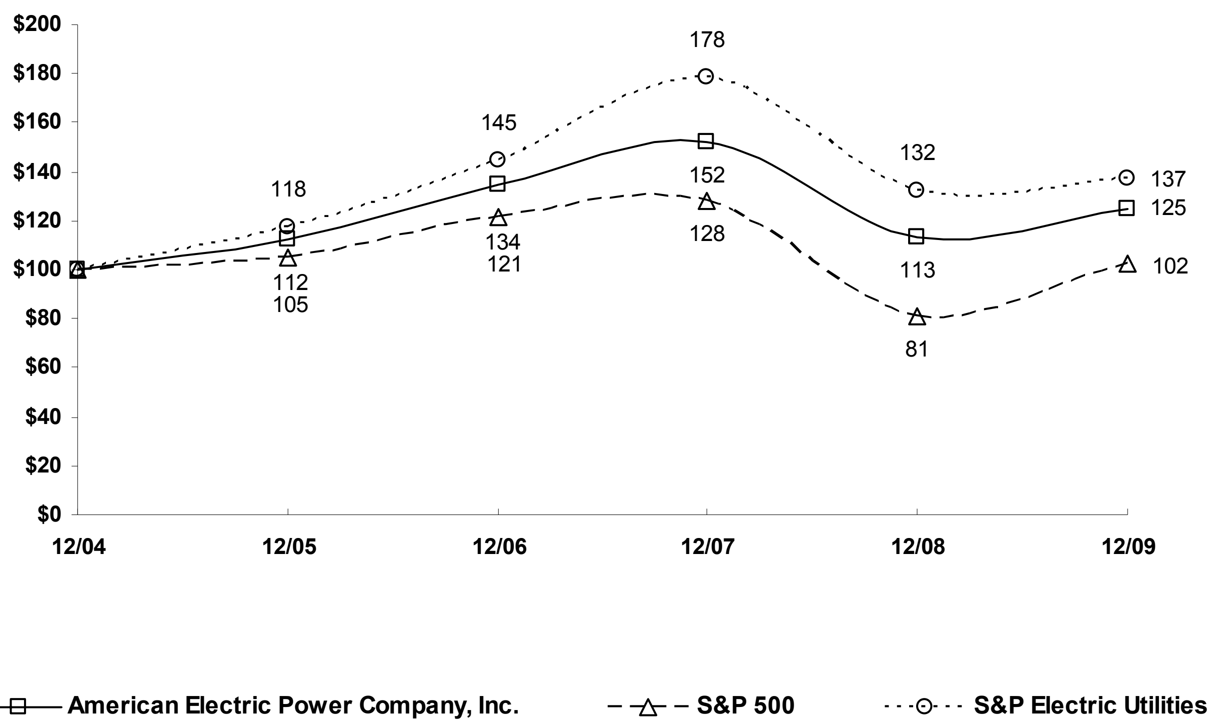
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2009	$ 36.51	$ 29.59	$ 34.79	$ 0.41
September 30, 2009	32.36	28.07	30.99	0.41
June 30, 2009	29.16	24.75	28.89	0.41
March 31, 2009	34.34	24.00	25.26	0.41
December 31, 2008	$ 37.28	$ 25.54	$ 33.28	$ 0.41
September 30, 2008	41.60	34.86	37.03	0.41
June 30, 2008	45.95	39.46	40.23	0.41
March 31, 2008	49.11	39.35	41.63	0.41

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2009, AEP had approximately 96,000 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 12/31/04 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

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

	2009	2008	2007	2006	2005
			(in millions)		
STATEMENTS OF INCOME DATA					
Total Revenues	$ 13,489	$ 14,440	$ 13,380	$ 12,622	$ 12,111
Operating Income	$ 2,771	$ 2,787	$ 2,319	$ 1,966	$ 1,927
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 1,370	$ 1,376	$ 1,153	$ 1,001	$ 1,043
Discontinued Operations, Net of Tax	-	12	24	10	27
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	1,370	1,388	1,177	1,011	1,070
Extraordinary Loss, Net of Tax	(5)	-	(79)	-	(225)(a)
Cumulative Effect of Accounting Change, Net of Tax	-	-	-	-	(17)
Net Income	1,365	1,388	1,098	1,011	828
Less: Net Income Attributable to Noncontrolling Interests	5	5	6	6	7
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,360	1,383	1,092	1,005	821
Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3	3	7
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,357	$ 1,380	$ 1,089	$ 1,002	$ 814
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 51,684	$ 49,710	$ 46,145	$ 42,021	$ 39,121
Accumulated Depreciation and Amortization	17,340	16,723	16,275	15,240	14,837
Net Property, Plant and Equipment	$ 34,344	$ 32,987	$ 29,870	$ 26,781	$ 24,284
Total Assets	$ 48,348	$ 45,155	$ 40,319	$ 37,877	$ 35,662
AEP Common Shareholders' Equity	$ 13,140	$ 10,693	$ 10,079	$ 9,412	$ 9,088
Noncontrolling Interests	$ -	$ 17	$ 18	$ 18	$ 14
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 61	$ 61	$ 61	$ 61	$ 61
Long-term Debt (b)	$ 17,498	$ 15,983	$ 14,994	$ 13,698	$ 12,226
Obligations Under Capital Leases (b)	$ 317	$ 325	$ 371	$ 291	$ 251
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 2.97	$ 3.40	$ 2.87	$ 2.52	$ 2.64
Discontinued Operations, Net of Tax	-	0.03	0.06	0.02	0.07
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	2.97	3.43	2.93	2.54	2.71
Extraordinary Loss, Net of Tax	(0.01)	-	(0.20)	-	(0.58)
Cumulative Effect of Accounting Change, Net of Tax	-	-	-	-	(0.04)
Basic Earnings per Share Attributable to AEP Common Shareholders	$ 2.96	$ 3.43	$ 2.73	$ 2.54	$ 2.09
Weighted Average Number of Basic Shares Outstanding (in millions)	459	402	399	394	390
Market Price Range:					
High	$ 36.51	$ 49.11	$ 51.24	$ 43.13	$ 40.80
Low	$ 24.00	$ 25.54	$ 41.67	$ 32.27	$ 32.25
Year-end Market Price	$ 34.79	$ 33.28	$ 46.56	$ 42.58	$ 37.09
Cash Dividends Paid per AEP Common Share	$ 1.64	$ 1.64	$ 1.58	$ 1.50	$ 1.42
Dividend Payout Ratio	55.41%	47.8%	57.9%	59.1%	67.9%
Book Value per AEP Common Share	$ 27.49	$ 26.35	$ 25.17	$ 23.73	$ 23.08

(a) Extraordinary Loss, Net of Tax for 2005 reflects TCC's stranded cost.

(b) Includes 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 39,000 megawatts of generating capacity, one of the largest complements of generation in the U.S., the majority of which provides a significant cost advantage in most 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.
- 215,800 miles of distribution lines that deliver electricity to 5.2 million customers.
- Substantial commodity transportation assets (more than 9,000 railcars, approximately 3,000 barges, 64 towboats, 29 harbor boats and a coal handling terminal with 18 million tons of annual capacity).

EXECUTIVE OVERVIEW

Economic Conditions

In 2009, our operations were impacted by difficult economic conditions. While our 2009 residential and commercial KWH sales were down moderately in comparison to 2008, our industrial KWH sales declined substantially in 2009 by 16%. Approximately half of the decrease was due to cutbacks or closures by 10 of our large metals producing customers. We also experienced varying decreases in KWH sales to customers in the transportation, plastics, rubber and paper manufacturing industries. We forecast a recovery in industrial sales volumes of approximately 5% in 2010 as compared to 2009.

Margins from off-system sales decreased due to reductions in sales volumes and weak market prices for power, reflecting reduced overall demand for electricity. Off-system sales volumes decreased by 50% in 2009. We forecast a recovery in off-system sales volumes of approximately 60% in 2010 as compared to 2009.

Regulatory Activity

Significant 2009 Approved Rate Increases

Arkansas – The APSC approved a base rate increase that provides for an $18 million annual increase in revenues effective December 2009 and a decrease in annual depreciation rates of $12 million. The order also includes a separate rider of approximately $11 million annually for the recovery of carrying costs, depreciation and operation and maintenance expenses on the Stall Unit once it is placed in service as expected in mid-2010.

Indiana – The IURC approved a base rate increase that provides for an annual increase in revenues of $42 million effective March 2009, including a $19 million base rate increase and $23 million in additional tracker revenues for certain incurred costs, subject to true-up.

Ohio – The PUCO issued an order that modified and approved CSPCo's and OPCo's ESP filings that authorized capped rate increases during the three-year ESP period and also authorized a FAC. The order provided for a $94 million and $103 million increase in CSPCo's and OPCo's 2009 revenues. Projected revenue increases for CSPCo and OPCo under the capped rate provision of the ESP order are listed below:

	Projected Revenue Increases	
	2010	**2011**
	(in millions)	
CSPCo	$ 109	$ 116
OPCo	125	153

Changes in customer usage may have an impact on actual revenue increases under the capped rate provision of the ESP order. In addition to the revenue increases, net income was positively affected by material noncash FAC deferrals in 2009 and will continue through 2011, including a carrying charge at CSPCo's and OPCo's weighted average cost of capital. These deferrals will be collected through a non-bypassable surcharge from 2012 through 2018. Several notices of appeal are pending at the Supreme Court of Ohio.

Oklahoma – The OCC approved PSO's Capital Reliability Rider (CRR) filing to recover up to $30 million under the CRR on an annual basis beginning in January 2010 until PSO's next base rate order. The order approving the CRR requires PSO to file a base rate case no later than July 2010.

Virginia – The Virginia SCC issued an order which provides for a $130 million annual fuel revenue increase effective August 2009 to recover deferred and projected fuel costs. The Virginia SCC also approved APCo's Transmission Rate Adjustment Clause effective December 2009 which will increase annual revenue by $22 million to provide for eligible transmission service costs billed by PJM.

West Virginia – For APCo's and WPCo's Expanded Net Energy Cost (ENEC) filing, the WVPSC issued an order granting a $355 million increase effective October 2009 over a four-year phase-in period plus a fixed annual carrying cost rate of 4% to recover fuel, purchased power and other deferred and projected energy costs.

Pending Rate Cases

Kentucky – In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by $124 million annually based on an 11.75% return on common equity. New rates are expected to become effective in July 2010.

Texas – In August 2009, SWEPCo filed a rate case with the PUCT to increase its base rates by approximately $75 million annually including a return on equity of 11.5%. The filing includes financing cost riders of $32 million related to construction of the Stall Unit and Turk Plant, a vegetation management rider of $16 million and other requested increases of $27 million. The March 2010 hearings were suspended for the parties to pursue settlement discussions.

Virginia – In July 2009, APCo filed a generation and distribution base rate increase with the Virginia SCC of $154 million annually based on a 13.35% return on common equity. The new rates, subject to refund, became effective in December 2009. To date, intervenors have filed testimony which management estimates could result in revenue increases ranging from $63 million to $94 million. In February 2010, in response to customer concerns regarding higher electric bills, APCo, in working with service area legislators, proactively developed proposed legislation to suspend the collection of interim rates. The Governor of Virginia approved this legislation.

Regulatory Strategy and Announced 2010 Base Rate Cases

We intend to seek increases in base rates where our returns on equity are not considered reasonable. We also intend to actively pursue the recovery of significant 2009 storm restoration costs and new investments in generation, transmission and distribution service and environmental compliance. We will continue to pursue cost recovery mechanisms in 2010 that will ensure ratepayers and shareholders are treated fairly.

To date, we have filed or given notice of the following base rate cases:

Michigan – In January 2010, I&M filed for a $63 million increase in annual base rates based on an 11.75% return on common equity. I&M can request interim rates, subject to refund, after six months. A final order from the MPSC is required within one year.

West Virginia – APCo provided notice to the WVPSC that it intends to file a base rate case, now planned for March 2010.

Global Warming

Climate change is a global issue and the United States should assume a leadership role in developing a new international approach that will address growing emissions from all nations. In 2009, the U.S. House of Representatives passed a comprehensive energy and climate change bill. The Senate Environmental and Public Works Committee passed legislation out of committee. The Federal EPA also issued a final mandatory greenhouse gas reporting rule covering a broad range of facilities. Mandated CO_2 emission reductions will have significant capital and operating cost impacts on the AEP System. It will also impact decisions concerning the retirement of some of our smaller coal generating units.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In October 2009, APCo started injecting CO_2 into the underground storage facilities.

In December 2009, APCo received approval for federal grant funding of $334 million for a new commercial scale project at the Mountaineer Plant to capture and store carbon for 235 MW of the plant's existing 1,300 MW of capacity by 2015. The cost of this proposed project is currently estimated to be $668 million, excluding Asset Retirement Obligations. We are currently seeking partners in this project to share the projected remaining costs.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor's warranty, insurance and the regulatory process. Upon receipt of accidental outage insurance proceeds, I&M mitigated the incremental fuel cost of replacement power to ratepayers. I&M repaired Unit 1 and it resumed operations in December 2009 at reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The APSC, LPSC and PUCT approved SWEPCo's application to build the Turk Plant.

In June 2009, the Arkansas Court of Appeals issued a unanimous decision that would reverse the APSC's grant of its permission for construction of the Turk Plant to serve Arkansas retail customers. In October 2009, the Arkansas Supreme Court granted the petitions filed by SWEPCo and the APSC to review the Arkansas Court of Appeals decision.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality (ADEQ) and commenced construction at the site. The Turk Plant cannot be placed in service without its air permit. Certain parties filed an appeal of the air permit approval with the Arkansas Pollution Control and Ecology Commission (APCEC). In January 2010, the APCEC upheld the air permit. In February 2010, the parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal of the APCEC's decision with the Circuit Court of Hempstead County, Arkansas. The same parties filed a petition with the Federal EPA to review the air permit. In December 2009, the Federal EPA rejected the parties' petition on every issue except one, where the Federal EPA asked the ADEQ to supplement the air permit record on one aspect of its Best Available Control Technology analysis.

If for any reason SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service, it would reduce net income, cash flows and possibly impact financial condition.

Transmission Initiatives

We continue our pursuit of transmission opportunities throughout the U.S. In 2009, we announced that our recently formed transmission company, AEP Transmission Company, LLC, will pursue new transmission investments within our retail service territories. We plan to invest approximately $120 million in these transmission opportunities in 2010. Through a joint venture, we have existing and planned transmission projects in ERCOT. We continue to pursue other transmission opportunities outside of our retail service territories through joint ventures with other partners.

gridSMART^{SM}

We are currently introducing and implementing our gridSMART^{SM} project in portions of our retail service territories. gridSMART^{SM} is a combination of advanced technologies and consumer programs intended to improve electricity distribution efficiency, reduce power demand thereby reducing power plant emissions and help consumers manage their electricity use and costs. In 2009, CSPCo received approval for federal grant funding of $75 million from the U.S. Department of Energy for the Ohio gridSMART^{SM} demonstration program. These funds will provide capital to reduce the ultimate cost to customers. Subject to appropriate cost recovery, we intend to implement gridSMART^{SM} in other sections of our retail service territories.

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable 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.

AEP River Operations

- Commercial barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 49% of the barging is for transportation of agricultural products, 27% for coal, 8% for steel and 16% for other commodities.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT.

The table below presents our consolidated Income Before Discontinued Operations and Extraordinary Loss by segment for the years ended December 31, 2009, 2008 and 2007.

	Years Ended December 31,		
	2009	2008	2007
		(in millions)	
Utility Operations	$ 1,329	$ 1,123	$ 1,040
AEP River Operations	47	55	61
Generation and Marketing	41	65	67
All Other (a)	(47)	133	(15)
Income Before Discontinued Operations and Extraordinary Loss	$ 1,370	$ 1,376	$ 1,153

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually settle and completely expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.

AEP CONSOLIDATED

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss in 2009 decreased $6 million compared to 2008 primarily due to income in 2008 from the cash settlement of a purchase power and sale agreement with TEM offset by an increase in income from our Utility Operations segment. The increase in Utility Operations segment net income primarily relates to rate increases in our Indiana, Ohio, Oklahoma and Virginia service territories partially offset by lower industrial sales as well as lower off-system sales margins due to lower sales volumes and lower market prices.

Average basic shares outstanding increased to 459 million in 2009 from 402 million in 2008 primarily due to the issuance of 69 million shares of AEP common stock. Actual shares outstanding were 478 million as of December 31, 2009.

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss in 2008 increased $223 million compared to 2007 primarily due to income from the cash settlement received in 2008 related to a purchase power and sale agreement with TEM, the 2008 deferral of Oklahoma ice storm expenses incurred in 2007 and base rate increases in our Ohio, Texas and Virginia service territories. These increases over 2007 were partially offset by higher interest expense and fuel expense and a provision for refund recorded to reflect the impact of an order issued in November 2008 by the FERC regarding the affiliate allocation of off-system sales margins under the SIA and the CSW Operating Agreement.

Average basic shares outstanding increased to 402 million in 2008 from 399 million in 2007 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 406 million as of December 31, 2008. In 2008, we contributed 1,250,000 shares of common stock held in treasury to the AEP Foundation.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

Our Utility Operations segment includes 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.

	Years Ended December 31,		
	2009	2008	2007
		(in millions)	
Revenues	$ 12,803	$ 13,566	$ 12,655
Fuel and Purchased Power	4,420	5,622	4,838
Gross Margin	8,383	7,944	7,817
Depreciation and Amortization	1,561	1,450	1,483
Other Operating Expenses	4,162	4,114	4,129
Operating Income	2,660	2,380	2,205
Other Income, Net	138	173	105
Interest Expense	916	915	784
Income Tax Expense	553	515	486
Income Before Discontinued Operations and Extraordinary Loss	$ 1,329	$ 1,123	$ 1,040

Summary of KWH Energy Sales for Utility Operations
For the Years Ended December 31, 2009, 2008 and 2007

Energy/Delivery Summary	2009	2008	2007
		(in millions of KWH)	
Retail:			
Residential	58,232	58,892	59,182
Commercial	49,925	50,382	50,611
Industrial	54,428	64,508	63,555
Miscellaneous	3,048	3,114	3,186
Total Retail (a)	165,633	176,896	176,534
Wholesale	29,679	43,085	42,917
Total KWHs	195,312	219,981	219,451

(a) Includes energy delivered to customers served by AEP's Texas Wires Companies.

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations
For the Years Ended December 31, 2009, 2008 and 2007

	2009	2008	2007
		(in degree days)	
Eastern Region			
Actual – Heating (a)	3,097	3,154	3,014
Normal – Heating (b)	3,040	3,018	3,042
Actual – Cooling (c)	816	949	1,266
Normal – Cooling (b)	1,011	986	978
Western Region			
Actual – Heating (a)	970	992	1,026
Normal – Heating (b)	984	1,010	1,028
Actual – Cooling (d)	2,439	2,252	2,318
Normal – Cooling (b)	2,344	2,320	2,326

(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 cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

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2009 Compared to 2008

Reconciliation of Year Ended December 31, 2008 to Year Ended December 31, 2009
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2008		$ 1,123
Changes in Gross Margin:		
Retail Margins	549	
Off-system Sales	(333)	
Transmission Revenues	25	
Other Revenues	198	
Total Change in Gross Margin		439
Total Expenses and Other:		
Other Operation and Maintenance	(46)	
Depreciation and Amortization	(111)	
Taxes Other Than Income Taxes	(2)	
Interest and Investment Income	(38)	
Carrying Costs Income	(36)	
Allowance for Equity Funds Used During Construction	37	
Interest Expense	(1)	
Equity Earnings of Unconsolidated Subsidiaries	2	
Total Expenses and Other		(195)
Income Tax Expense		(38)
Year Ended December 31, 2009		$ 1,329

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $549 million primarily due to the following:
  - A $187 million increase related to the PUCO's approval of our Ohio ESPs, a $170 million increase related to base rates and recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $75 million increase in base rates in Oklahoma, a $42 million net rate increase for I&M and $50 million of rate increases in our other jurisdictions.
  - A $201 million increase in fuel margins in Ohio primarily due to the deferral of fuel costs by CSPCo and OPCo in 2009. The PUCO's March 2009 approval of CSPCo's and OPCo's ESPs allows for the deferral of fuel and related costs during the ESP period.
  - A $102 million increase due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA.
  - A $68 million increase due to lower PJM and other costs as the result of lower generation sales.

  These increases were partially offset by:
  - A $214 million decrease in margins from industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in our service territories.
  - A $78 million decrease in fuel margins due to higher fuel and purchased power costs related to the Cook Plant Unit 1 shutdown. This decrease in fuel margins was offset by a corresponding increase in Other Revenues as discussed below.
  - A $52 million decrease in usage primarily due to a 14% decrease in cooling degree days in our eastern region.
  - A $29 million decrease related to favorable coal contract amendments in 2008.
- Margins from Off-system Sales decreased $333 million primarily due to lower physical sales volumes and lower margins in our eastern service territory reflecting lower market prices, partially offset by higher trading and marketing margins.
- Transmission Revenues increased $25 million primarily due to increased rates in the ERCOT and SPP regions.

- Other Revenues increased $198 million primarily due to the Cook Plant accidental outage insurance proceeds of $185 million. I&M reduced customer bills by approximately $78 million for the cost of replacement power during the outage period. This increase in revenues was offset by a corresponding decrease in Retail Margins as discussed above.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $46 million primarily due to the following:
  - The 2008 deferral of $74 million of previously expensed Oklahoma ice storm costs resulting from an OCC order approving recovery of January and December 2007 ice storm expenses.
  - A $64 million increase in administrative and general expenses primarily for employee benefits.
  - A $48 million increase in storm restoration expenses due to the December 2009 winter storm in Tennessee, Virginia and West Virginia. We plan to seek recovery of these expenses.
  - A $32 million increase in demand side management, energy efficiency and vegetation management programs.
  - A $29 million increase in recoverable transmission service expenses.
  - A $14 million increase due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.

  These increases were partially offset by:
  - A $67 million decrease in distribution and customer account expenses.
  - A $51 million decrease in transmission expenses related to cost recovery rider amortization in Ohio and rate adjustment clause deferrals in Virginia.
  - A $43 million decrease in other operating expenses including lower charitable contributions.
  - A $39 million decrease in RTO fees, forestry and other transmission expenses.
  - A $15 million decrease in plant outage and other plant operating and maintenance expenses, including lower removal costs.
- Depreciation and Amortization increased $111 million primarily due to higher depreciable property balances as the result of environmental improvements placed in service at OPCo and various other property additions and higher depreciation rates for OPCo related to shortened depreciable lives for certain generating facilities.
- Interest and Investment Income decreased $38 million primarily due to lower interest income related to federal income tax refunds filed with the IRS and the recognition of other-than-temporary losses related to equity investments held by our protected cell of EIS in 2009.
- Carrying Costs Income decreased $36 million primarily due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- Allowance for Equity Funds Used During Construction increased $37 million as a result of construction at SWEPCo's Turk Plant and Stall Unit and the reapplication of "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective April 2009.
- Interest Expense increased $1 million primarily due to a $52 million increase in interest expense related to increased long-term debt borrowings partially offset by interest expense of $47 million recorded in 2008 related to the 2008 SIA adjustment for off-system sales margins in accordance with the FERC's 2008 order.
- Income Tax Expense increased $38 million primarily due to an increase in pretax book income offset by the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

2008 Compared to 2007

Reconciliation of Year Ended December 31, 2007 to Year Ended December 31, 2008
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2007		$ 1,040
Changes in Gross Margin:		
Retail Margins	159	
Off-system Sales	(90)	
Transmission Revenues	33	
Other Revenues	25	
Total Change in Gross Margin		127
Total Expenses and Other:		
Other Operation and Maintenance	35	
Gain on Dispositions of Assets, Net	(19)	
Depreciation and Amortization	33	
Taxes Other Than Income Taxes	(1)	
Interest and Investment Income	21	
Carrying Costs Income	32	
Allowance for Equity Funds Used During Construction	12	
Interest Expense	(131)	
Equity Earnings of Unconsolidated Subsidiaries	3	
Total Expenses and Other		(15)
Income Tax Expense		(29)
Year Ended December 31, 2008		$ 1,123

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $159 million primarily due to the following:
  - A $206 million increase related to net rate increases implemented in our Ohio jurisdictions, a $53 million increase related to recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $25 million net increase in rates in Oklahoma, a $21 million increase in base rates in Texas and an $18 million increase in base rates in Virginia.
  - A $99 million net increase due to adjustments recorded in 2007 related to the 2007 Virginia base rate case which included a second quarter 2007 provision for revenue refund.
  - A $50 million increase related to increased usage by Ormet, an industrial customer in Ohio.
  - A $40 million net increase due to favorable coal contract amendments in 2008.
  - A $17 million increase due to a 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding.
  - An $8 million increase in sales to municipal and cooperative customers, primarily in CSPCo's service territory.

  These increases were partially offset by:
  - A $186 million increase in fuel expense in Ohio. CSPCo and OPCo did not have active fuel clauses in 2008 and 2007.
  - A $102 million decrease due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA.
  - A $65 million decrease in usage primarily due to a 26% decrease in cooling degree days in our eastern region and a 10% decrease in cooling degree days in our western region.
  - A $40 million net decrease in retail sales primarily due to lower industrial sales in Indiana, Ohio and Virginia as a result of the economic slowdown in the second half of 2008.

- Margins from Off-system Sales decreased $90 million primarily due to the following:
  - A $45 million decrease due to higher trading margins realized in 2007 and the favorable effects of a fuel reconciliation in our western service territory in 2007. This decrease was partially offset by higher physical off-system sales in our eastern territory as the result of higher realized prices and higher PJM capacity revenues.
  - A $46 million decrease primarily due to an increase in sharing of off-system sales margins with customers resulting from a full year of sharing in Virginia in 2008 compared to one quarter of sharing in 2007.
- Transmission Revenues increased $33 million primarily due to increased rates.
- Other Revenues increased $25 million primarily due to increased third-party engineering and construction work, an increase in pole attachment revenue and an unfavorable provision for TCC for the refund of bonded rates recorded in 2007.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $35 million primarily due to the following:
  - An $84 million decrease due to distribution expense recorded in 2007 for ice storm costs incurred in January and December 2007 and a $74 million decrease related to the deferral of these costs in the first quarter of 2008.
  - A $77 million decrease related to the recording of NSR settlement costs in September 2007.
  - A $9 million decrease related to the establishment of a regulatory asset in the third quarter of 2008 for Virginia's share of previously expensed NSR settlement costs.

  These decreases were partially offset by:
  - A $60 million increase in recoverable PJM expenses in Ohio.
  - A $38 million increase in tree trimming, reliability and other transmission and distribution expenses.
  - A $28 million increase in generation plant operations and maintenance expense.
  - A $28 million increase in recoverable customer account expenses related to the Universal Service Fund for Ohio customers who qualify for payment assistance.
  - A $22 million increase due to storm costs incurred in 2008 by SWEPCo and I&M.
  - A $13 million increase in maintenance expense at the Cook Plant.
  - A $12 million increase due to the amortization of deferred 2007 Oklahoma ice storm costs in 2008.
  - A $10 million increase related to the write-off of the unrecoverable pre-construction costs for PSO's cancelled Red Rock Generating Facility in the first quarter of 2008.
- Gain on Dispositions of Assets, Net decreased $19 million primarily due to the expiration of the earnings sharing agreement with Centrica from the sale of our Texas REPs in 2002. In 2007, we received the final earnings sharing payment of $20 million.
- Depreciation and Amortization expense decreased $33 million primarily due to lower commission-approved depreciation rates in Indiana, Michigan, Oklahoma and Texas and lower Ohio regulatory asset amortization, partially offset by higher depreciable property balances and prior year adjustments related to the Virginia base rate case.
- Interest and Investment Income increased $21 million primarily due to the favorable effect of claims for refund filed with the IRS.
- Carrying Costs Income increased $32 million primarily due to increased cost deferrals in Virginia and Oklahoma.
- Allowance for Equity Funds Used During Construction increased $12 million primarily due to various generation projects under construction.
- Interest Expense increased $131 million primarily due to additional debt issued and higher interest rates on variable rate debt and interest expense of $47 million on off-system sales margins in accordance with the FERC's order related to the SIA.
- Income Tax Expense increased $29 million due to an increase in pretax income.

AEP RIVER OPERATIONS

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $55 million in 2008 to $47 million in 2009 primarily due to lower revenues as a result of a weak import market.

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $61 million in 2007 to $55 million in 2008 primarily due to rising diesel fuel prices, travel restrictions caused by significant flooding on various internal waterways throughout 2008, the impact of Hurricanes Ike and Gustav and other adverse operating conditions. Additionally, decreases in import demand and grain export demand resulted in lower freight demand as a result of a slowing U.S. economy.

GENERATION AND MARKETING

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $65 million in 2008 to $41 million in 2009 primarily due to lower gross margins at the Oklaunion Generating Station as a result of lower power prices in ERCOT and decreased generation from our wind farms.

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $67 million in 2007 to $65 million in 2008 primarily due to the sale in 2007 of our equity investment in Sweeny and related contracts which resulted in $37 million of after-tax income offset by higher gross margins from marketing activities and improved plant performance and hedging activities from our share of the Oklaunion Generating Station.

ALL OTHER

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from All Other decreased from income of $133 million in 2008 to a loss of $47 million in 2009. In 2008, we had after-tax income of $164 million from a litigation settlement of a purchase power and sale agreement with TEM.

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from All Other increased from a loss of $15 million in 2007 to income of $133 million in 2008. In 2008, we had after-tax income of $164 million from a litigation settlement of a purchase power and sale agreement with TEM.

AEP SYSTEM INCOME TAXES

2009 Compared to 2008

Income Tax Expense decreased $67 million between 2008 and 2009 primarily due to a decrease in pretax book income and the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

2008 Compared to 2007

Income Tax Expense increased $126 million between 2007 and 2008 primarily due to an increase in pretax book income.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2009, we maintained our strong financial condition as reflected by our issuances of $1.64 billion (net proceeds) of AEP common stock in April and $2.3 billion of long-term debt primarily to pay our 2008 draws on the credit facilities, fund our construction program and refinance debt maturities. These issuances help to support our investment grade ratings and maintain financial flexibility.

DEBT AND EQUITY CAPITALIZATION

	December 31,			
	2009		2008	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 17,498	56.8%	$ 15,983	55.6%
Short-term Debt	126	0.4	1,976	6.9
Total Debt	17,624	57.2	17,959	62.5
Preferred Stock of Subsidiaries	61	0.2	61	0.2
AEP Common Equity	13,140	42.6	10,693	37.2
Noncontrolling Interests	-	-	17	0.1
Total Debt and Equity Capitalization	$ 30,825	100.0%	$ 28,730	100.0%

Our ratio of debt to total capital improved from 62.5% to 57.2% in 2009 due to the issuance of common shares and the application of the proceeds to reduce debt. Our 2009 financing activities and prudent management of capital expenditures during the current economic conditions will reduce our expected 2010 capital market requirements and continue to strengthen our balance sheet.

Approximately $1.6 billion of our $17 billion of outstanding long-term debt will mature in 2010, excluding payments due for securitization bonds which we recover directly from ratepayers. In September 2009, OPCo issued $500 million of 5.375% senior unsecured notes which will be used to pay at maturity some of its outstanding debt due in 2010. We believe that our projected cash flows from operating activities are sufficient to support our ongoing operations. Our debt matures in 2010 as follows:

	(in millions)
First Quarter	$ 498
Second Quarter	703
Third Quarter	12
Fourth Quarter	375

LIQUIDITY

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. At December 31, 2009, we had $3.6 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a sale of receivables agreement. We are committed to maintaining adequate liquidity. 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 long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2009, our available liquidity was approximately $3.4 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	March 2011
Revolving Credit Facility	1,454	April 2012
Revolving Credit Facility	627	April 2011
Total	3,581	
Cash and Cash Equivalents	490	
Total Liquidity Sources	4,071	
Less: AEP Commercial Paper Outstanding	119	
Letters of Credit Issued	568	
Net Available Liquidity	$ 3,384	

We have credit facilities totaling $3.6 billion, of which two $1.5 billion credit facilities support our commercial paper program. The two $1.5 billion credit facilities allow for the issuance of up to $750 million as letters of credit under each credit facility. We also have a $627 million credit facility which can be utilized for letters of credit or draws.

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. In 2009, we repaid the $2 billion borrowed in 2008 under the credit facilities. The maximum amount of commercial paper outstanding during 2009 was $614 million. The weighted-average interest rate for our commercial paper during 2009 was 0.61%.

Sale of Receivables

In 2009, we renewed our sale of receivables agreement through July 2010. The sale of receivables agreement provides a commitment of $750 million from banks and commercial paper conduits to purchase receivables. We intend to extend or replace the sale of receivables agreement at maturity.

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 in our revolving credit agreements. At December 31, 2009, this contractually-defined percentage was 53.9%. Nonperformance of these covenants could result in an event of default under these credit agreements. At December 31, 2009, 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 major 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 in a majority of our non-exchange traded commodity contracts, which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At December 31, 2009, 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 399 consecutive quarters. The Board of Directors declared a quarterly dividend of $0.41 per share in January 2010. Future dividends may vary depending upon our profit levels, operating cash flows and capital requirements, as well as financial and other business conditions existing at the time. We have the option to defer interest payments on the AEP Junior Subordinated Debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock. We believe that these restrictions will not have a material effect on our cash flows, financial condition or limit any dividend payments in the foreseeable future.

Credit Ratings

Our credit ratings as of December 31, 2009 were as follows:

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

In 2009, Moody's:

- Placed AEP on negative outlook.
- Downgraded TNC to Baa2 and placed it on stable outlook.
- Changed the rating outlook for APCo from negative to stable.
- Downgraded SWEPCo to Baa3 and placed it on stable outlook.
- Downgraded OPCo to Baa1 and placed it on stable outlook.

In 2009, Fitch:

- Changed its rating outlook for SWEPCo and TCC from stable to negative.
- Downgraded APCo's senior unsecured rating to BBB and placed it on stable outlook.

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.

	Years Ended December 31,		
	2009	2008	2007
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 411	$ 178	$ 301
Net Cash Flows from Operating Activities	2,475	2,581	2,394
Net Cash Flows Used for Investing Activities	(2,916)	(4,027)	(3,921)
Net Cash Flows from Financing Activities	520	1,679	1,404
Net Increase (Decrease) in Cash and Cash Equivalents	79	233	(123)
Cash and Cash Equivalents at End of Period	$ 490	$ 411	$ 178

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.

Operating Activities

	Years Ended December 31, 2009	2008	2007
		(in millions)	
Net Income	$ 1,365	$ 1,388	$ 1,098
Less: Discontinued Operations, Net of Tax	-	(12)	(24)
Income Before Discontinued Operations	1,365	1,376	1,074
Depreciation and Amortization	1,597	1,483	1,513
Other	(487)	(278)	(193)
Net Cash Flows from Operating Activities	$ 2,475	$ 2,581	$ 2,394

Net Cash Flows from Operating Activities were $2.5 billion in 2009 consisting primarily of Income Before Discontinued Operations of $1.4 billion and $1.6 billion of noncash Depreciation and Amortization. Other changes 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. Significant changes in other items include the negative impact on cash of an increase in coal inventory reflecting decreased customer demand for electricity, an increase in under-recovered fuel primarily in Ohio and West Virginia and an increase in accrued tax benefits resulting from a net income tax operating loss in 2009. Deferred Income Taxes increased primarily due to the American Recovery and Reinvestment Act of 2009 extending bonus depreciation provisions, a change in tax accounting method and an increase in tax versus book temporary differences from operations.

Net Cash Flows from Operating Activities were $2.6 billion in 2008 consisting primarily of Income Before Discontinued Operations of $1.4 billion and $1.5 billion of noncash Depreciation and Amortization. Other changes 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. Net Cash Flows from Operating Activities increased in 2008 due to the TEM settlement. Under-recovered fuel costs and fuel, materials and supplies inventories increased working capital requirements due to the higher cost of coal and natural gas. Deferred Income Taxes increased primarily due to the enactment of the Economic Stimulus Act which enhanced expensing provisions for certain assets placed in service in 2008 and provided for a 50% bonus depreciation provision for certain assets placed in service in 2008.

Net Cash Flows from Operating Activities were $2.4 billion in 2007 consisting primarily of Income Before Discontinued Operations of $1.1 billion and $1.5 billion of noncash Depreciation and Amortization. Other changes 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. Significant changes in other items resulted in lower cash from operations due to increased accounts receivable of $113 million for new contracts in the generation and marketing segment and increased utility segment receivables and the CTC refunds in Texas.

Investing Activities

	Years Ended December 31, 2009	2008	2007
		(in millions)	
Construction Expenditures	$ (2,792)	$ (3,800)	$ (3,556)
Acquisitions of Assets	(104)	(160)	(512)
Proceeds from Sales of Assets	278	90	222
Other	(298)	(157)	(75)
Net Cash Flows Used for Investing Activities	$ (2,916)	$ (4,027)	$ (3,921)

Net Cash Flows Used for Investing Activities were $2.9 billion in 2009 primarily due to Construction Expenditures for our new generation, environmental and distribution investment plan. Proceeds from Sales of Assets in 2009 includes $104 million relating to the sale of a portion of Turk Plant to joint owners as planned and $95 million for sales of Texas transmission assets to ETT.

Net Cash Flows Used for Investing Activities were $4 billion in 2008 primarily due to Construction Expenditures for distribution, environmental and new generation investment.

Net Cash Flows Used for Investing Activities were $3.9 billion in 2007 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan and purchases of gas-fired generating units.

Financing Activities

	Years Ended December 31, 2009	2008	2007
		(in millions)	
Issuance of Common Stock, Net	$ 1,728	$ 159	$ 144
Issuance/Retirement of Debt, Net	(360)	2,266	1,902
Dividends Paid on Common Stock	(758)	(666)	(636)
Other	(90)	(80)	(6)
Net Cash Flows from Financing Activities	$ 520	$ 1,679	$ 1,404

Net Cash Flows from Financing Activities in 2009 were $520 million. Issuance of Common Stock, Net of $1.7 billion is comprised of our issuance of 69 million shares of common stock with net proceeds of $1.64 billion and additional shares through our dividend reinvestment, employee savings and incentive programs. Our net debt retirements were $360 million. The net retirements included the repayment of $2 billion outstanding under our credit facilities and retirement of $816 million of long-term debt and issuances of $1.9 billion of senior unsecured and debt notes and $431 million of pollution control bonds. We paid common stock dividends of $758 million.

Net Cash Flows from Financing Activities were $1.7 billion in 2008 primarily due to the borrowing under our credit facility to provide liquidity during the 2008 credit market. We paid common stock dividends of $666 million.

Net Cash Flows from Financing Activities were $1.4 billion in 2007 primarily from issuance of debt to fund our construction program. We paid common stock dividends of $636 million.

The following financing activities occurred during 2009:

AEP Common Stock:

- In April 2009, we issued 69 million shares of common stock with net proceeds of $1.64 billion.
- During 2009, we issued 3 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $88 million.

Debt:

- During 2009, we issued approximately $2.3 billion of long-term debt, including $1.7 billion of senior notes at interest rates ranging from 5.15% to 8.13%, $431 million of pollution control revenue bonds ($104 million at variable rates and $327 million at fixed interest rates ranging from 3.875% to 6.3%) and $196 million of notes at interest rates ranging from 5.44% to 8.03%. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2009, we entered into $400 million of interest rate derivatives and settled $421 million of such transactions. The settlements resulted in net cash receipts of $20 million. As of December 31, 2009, we had in place interest rate derivatives designated as cash flow hedges with a notional amount of $79 million in order to hedge risk exposure of variable interest rate debt.
- At December 31, 2009, we had credit facilities totaling $3 billion to support our commercial paper program and short-term borrowing. As of December 31, 2009, we had $119 million of commercial paper outstanding. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $614 million in June 2009 and the weighted average interest rate of commercial paper outstanding during the year was 0.61%.

In 2010:

- In January 2010, TCC retired $86 million of its outstanding Securitization Bonds.
- We expect to refinance approximately $1.2 billion of the $1.6 billion of long-term debt that will mature in 2010.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $2.2 billion of construction expenditures for 2010. 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 cash flows from operations and financing activities.

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 bank conduits. Under the sale of receivables agreement, AEP Credit sells an interest in a portion of the receivables it acquires from affiliated utilities to the bank conduits and receives cash. We have no ownership interest in the conduits and, in accordance with GAAP, are not required to consolidate these entities. AEP Credit continues 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 cash collections.

AEP Credit's sale of receivables agreement expires in July 2010. We intend to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of $750 million to purchase receivables from AEP Credit. At December 31, 2009, AEP Credit had $631 million of receivable sales outstanding. For the remaining receivables left unsold to the bank conduits, AEP Credit maintains an interest in the receivables 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. See "SFAS 166 "Accounting for Transfers of Financial Assets" (SFAS 166)" section of Note 2.

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 $960 million as of December 31, 2009.

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 13. 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 initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $40 million for the remaining railcars as of December 31, 2009. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five year renewal. At December 31, 2009, the maximum potential loss was approximately $25 million ($17 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair market value would produce a sufficient sales price to avoid any loss. We have other railcar lease arrangements that do not utilize this type of financing structure.

SUMMARY OBLIGATION INFORMATION

Our contractual cash 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, 2009:

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)	$ 126	$ -	$ -	$ -	$ 126
Interest on Fixed Rate Portion of Long-term Debt (b)	976	1,809	1,632	9,994	14,411
Fixed Rate Portion of Long-term Debt (c)	1,341	1,380	2,120	11,713	16,554
Variable Rate Portion of Long-term Debt (d)	400	85	100	425	1,010
Capital Lease Obligations (e)	85	116	58	147	406
Noncancelable Operating Leases (e)	334	646	462	1,538	2,980
Fuel Purchase Contracts (f)	3,087	4,370	2,484	7,873	17,814
Energy and Capacity Purchase Contracts (g)	82	144	195	1,161	1,582
Construction Contracts for Capital Assets (h)	464	958	930	-	2,352
Total	$ 6,895	$ 9,508	$ 7,981	$ 32,851	$ 57,235

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2009 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See “Long-term Debt” section of Note 14. Represents principal only excluding interest.
(d) See “Long-term Debt” section of Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.20% and 0.82% at December 31, 2009.
(e) See Note 13.
(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 obligations for energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

Our $110 million liability related to uncertainty in Income Taxes is not included above because we cannot reasonably estimate the cash flows by period.

Our pension funding requirements are not included in the above table. As of December 31, 2009, we expect to make contributions to our pension plans totaling $160 million in 2010. Estimated contributions of $286 million in 2011 and $296 million in 2012 may vary significantly based on market returns, changes in actuarial assumptions and other factors.

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, 2009, 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)	$ 568	$ -	$ -	$ -	$ 568
Guarantees of the Performance of Outside Parties (b)	-	-	-	65	65
Guarantees of Our Performance (c)	507	1,086	-	31	1,624
Total Commercial Commitments	$ 1,075	$ 1,086	$ -	$ 96	$ 2,257

(a) 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 variable rate Pollution Control Bonds. AEP, on behalf of our subsidiaries, and/or the subsidiaries issued all of these LOCs in the ordinary course of business. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. The maximum future payments of these LOCs are $568 million with maturities ranging from January 2010 to December 2010. See "Letters of Credit" section of Note 6.
(b) See "Guarantees of Third-Party Obligations" section of Note 6.
(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

THE AMERICAN RECOVERY AND REINVESTMENT ACT OF 2009

The American Recovery and Reinvestment Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on net income or financial condition. However, the bonus depreciation contributed to the 2009 federal, state and local net income tax operating loss, which will result in a future cash flow benefit.

In 2009, APCo received approval for $334 million in federal grant funding from the United States Department of Energy (DOE) for a new commercial scale project at the Mountaineer Plant to capture and store carbon. CSPCo received approval for $75 million in federal grant funding from the DOE for the gridSMART^{SM} demonstration program. These grants will provide capital to reduce the ultimate cost to our customers. Management is still negotiating terms of these grants with the DOE.

TRANSMISSION INITIATIVES

AEP Transmission Company, LLC (Utility Operations segment)

In 2006, we formed the AEP Transmission Company, LLC (AEP Transco). In 2009, AEP Transco formed seven wholly-owned transmission companies. AEP Transco is the holding company for the seven new transmission companies. These seven companies consist of:

- AEP Appalachian Transmission Company, Inc. (covering Virginia and Tennessee)
- AEP West Virginia Transmission Company, Inc.
- AEP Indiana Michigan Transmission Company, Inc.
- AEP Kentucky Transmission Company, Inc.
- AEP Ohio Transmission Company, Inc.
- AEP Oklahoma Transmission Company, Inc.
- AEP Southwestern Transmission Company, Inc. (covering Arkansas and Louisiana)

In December 2009, AEP, on behalf of these seven companies, filed formula rate requests with the FERC for transmission services under the PJM Open Access Transmission Tariff (OATT) and SPP OATT , as applicable, and to implement a transmission cost of service formula rate.

Starting in 2010, AEP Transco, through its seven subsidiaries, will make appropriate state regulatory filings and begin developing and owning new transmission assets that are physically connected to AEP's existing system. AEPSC and various AEP subsidiaries will provide services to AEP Transco. AEP Transco will not have any employees.

Joint Venture Initiatives (Utility Operations segment)

AEP is currently participating in the following joint venture initiatives:

Project Name	Location	Projected Completion Date	Owners (Ownership %)	Total Estimated Project Costs at Completion	AEP's Equity Method Investment at December 31, 2009	Approved Return on Equity
				(in thousands)		
ETT	Texas (ERCOT)	2017	MEHC Texas Transco, LLC (50%) AEP (50%)	$ 3,097,000 (a)	$ 53,496	9.96%
PATH (b)	Ohio/West Virginia	2014 (c)	Allegheny Energy (50%) AEP (50%)	1,800,000 (d)	15,763	14.3%
Tallgrass	Oklahoma	2013	OGE Energy (50%) ETA (50%) (e)	500,000	624	12.8%
Prairie Wind	Kansas	2013	Westar Energy (50%) ETA (50%) (e)	400,000	650	12.8%
Pioneer	Indiana	2015	Duke Energy (50%) AEP (50%)	1,000,000	-	12.54%

(a) In addition to ETT's current total estimated project costs of $3.1 billion, ETT plans to invest in additional transmission projects in ERCOT over the next several years. Future projects will be evaluated on a case-by-case basis. See "ETT 2007 Formation Appeal" section of Note 4.

(b) In September 2007, AEP Transmission Holding Company, LLC and AET PATH Company, LLC, a subsidiary of Allegheny Energy, Inc., formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH) and its subsidiaries. The PATH subsidiaries will operate as transmission utilities owning certain electric transmission assets within PJM.

(c) In December 2009, PJM released preliminary findings that the projected completion date may be pushed back based on voltage and service needs. A final report is expected in June 2010.

(d) PATH consists of the "Ohio Series" and the "West Virginia Series," both owned equally by subsidiaries of Allegheny Energy Inc. and AEP, and the "Allegheny Series" which is wholly-owned by a subsidiary of Allegheny Energy Inc. The total project is estimated to cost approximately $1.8 billion. AEP's estimated share of the project cost is approximately $600 million.

(e) Electric Transmission America, LLC (ETA) is a 50/50 joint venture with MidAmerican Energy Holdings Company (MEHC) America Transco, LLC and AEP Transmission Holding Company, LLC. ETA will be utilized as a vehicle to invest in selected transmission projects located in North America, outside of ERCOT. AEP Transmission Holding Company, LLC owns 25% of Tallgrass and Prairie Wind through its ownership interest in ETA.

SIGNIFICANT FACTORS

REGULATORY ISSUES

Ohio Electric Security Plan Filings

During 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs that established rates through 2011. The order also limits rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. The order provides a FAC for the three-year period of the ESP. Several notices of appeal are outstanding at the Supreme Court of Ohio and an order is expected from the PUCO related to the SEET methodology. See "Ohio Electric Security Plan Filings" section of Note 4.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor's warranty, insurance and the regulatory process. Upon receipt of accidental insurance proceeds, I&M mitigated the incremental fuel cost of replacement power to ratepayers. I&M repaired Unit 1 and it resumed operations in December 2009 at reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 6.

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. After a ruling from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. See "Texas Restructuring Appeals" section of Note 4.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in-service in 2012. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo's share estimated to cost $1.2 billion, excluding AFUDC. Notices of appeal are outstanding at the Arkansas Supreme Court and the Circuit Court of Hempstead County, Arkansas. Complaints are also outstanding at the LPSC and the Federal District Court for the Western District of Arkansas. See "Turk Plant" section of Note 4.

LITIGATION

In the ordinary course of business, we 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. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss 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 net income.

Environmental Litigation

The Federal EPA, a number of states and certain special interest groups filed complaints alleging that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. In 2007, we settled this litigation by a consent decree with the Federal EPA, the United States Department of Justice, the states and the special interest groups. Under the consent decree, we agreed to annual SO_2 and NO_x emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. We agreed to install FGD equipment at Big Sandy and at Muskingum River Plants no later than the end of 2015 and selective catalytic reduction and FGD emissions control equipment at Rockport Plant no later than the end of 2017 and 2019 for Unit 1 and Unit 2, respectively.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. The most significant source is the CAA's requirements to reduce emissions of SO_2, NO_x and PM from fossil fuel-fired power plants.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements to reduce CO_2 emissions to address concerns about global climate change.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) requiring specific reductions in SO_2 and NO_x emissions from power plants. In 2008, the D.C. Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. CAIR remains in effect while a new rulemaking is conducted. Nearly all of the states in which our power plants are located are covered by CAIR.

The Federal EPA issued a Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new state implementation plans (SIPs) including mercury requirements for existing coal-fired power plants. The D.C. Circuit Court of Appeals ruled that the Federal EPA's action delisting fossil fuel-fired power plants did not conform to the procedures specified in the CAA, and vacated and remanded the federal rules for both new and existing coal-fired power plants to the Federal EPA.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology 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.

Estimated Air Quality Environmental Investments

The CAIR, CAVR and the consent decree signed to settle the NSR litigation require us to make significant additional investments, some of which are estimable. 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 and their costs. In short, we cannot estimate our compliance costs with certainty and the actual costs to comply could differ significantly from the estimates discussed below.

The CAIR, CAVR and commitments in the consent decree will require installation of additional controls on our power plants through 2019. We plan to install additional scrubbers on 7,300 MW for SO_2 control. From 2010 to 2019, we estimate total environmental investment to meet these requirements of $5.5 billion including investment in scrubbers and other SO_2 equipment of approximately $4.6 billion. These estimates are highly uncertain due to the variability associated with: (1) the states' implementation of these regulatory programs, including the potential for SIPs or federal implementation plans that impose standards more stringent than CAIR; (2) additional rulemaking activities in response to the court decisions remanding the CAIR and CAMR; (3) the actual performance of the pollution control technologies installed on our units; (4) changes in costs for new pollution controls; (5) new generating technology developments; and (6) 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 net income, cash flows and possibly financial condition.

Global Warming

The topics of whether the earth is warming, how much and how fast, what role human activity plays, and what to do about it are very controversial and actively debated. The public policy makers and influencers in Washington and in the 11 states we serve have conflicting views. We are focused on taking, in the short term, actions that we see as prudent, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies, and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels, to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

We believe that this is a global issue and that the United States should assume a leadership role in developing a new international approach that will address growing emissions of CO_2 and other greenhouse gases (generally referred to as CO_2 in this discussion) from all nations, including developing countries. We support a reasonable approach to CO_2 emission reductions, that recognizes a reliable and affordable electric supply is vital to economic stability, and that allows sufficient time for technology development. We proposed that national and international policy for reasonable CO_2 controls should involve the following principles:

- Comprehensiveness
- Cost-effectiveness
- Realistic emission reduction objectives
- Reliable monitoring and verification mechanisms
- Incentives to develop and deploy CO_2 reduction technologies
- Removal of regulatory or economic barriers to CO_2 emission reductions
- Recognition for early actions/investments in CO_2 reduction/mitigation
- Inclusion of adjustment provisions if largest emitters in developing world do not take action

For additional information on global warming see Part I of the Annual Report under the headings entitled "Business – General – Environmental and Other Matters – Global Warming."

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act (ACES). ACES is a comprehensive energy and climate change bill that includes a number of provisions that would directly affect our business including energy efficiency and renewable electricity standards, funding for carbon capture and sequestration validation projects, CO_2 emission standards for new fossil fuel-fired electric generating plants and an economy-wide cap and trade program for large sources of CO_2 emissions that would reduce emissions by 17% in 2020 and just over 80% by 2050 from 2005 levels. The Senate Environmental and Public Works Committee passed legislation out of committee in September 2009 but it failed to advance to the Senate floor. Until legislation is final, we are unable to predict its impact on net income, cash flows and financial condition.

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through new legislation, several states and interest groups petitioned the Federal EPA to establish CO_2 emission standards under the existing requirements of the CAA. In September 2009, the Federal EPA issued a final mandatory CO_2 reporting rule covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for CO_2 emissions from new motor vehicles in December 2009, and is expected to issue final rules in March 2010. The Federal EPA has also issued a proposed scheme to streamline and phase in regulation of stationary source CO_2 emissions through the NSR's prevention of significant deterioration and CAA's Title V permitting programs. The Federal EPA stated its intent to finalize the permitting rule in conjunction with or following the final motor vehicle rule, and is reconsidering whether to include CO_2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units. If substantial CO_2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generating plants to limit CO_2 emissions and receive regulatory approvals to increase our rates, cost recovery could have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. In addition, to the extent our costs are relatively higher than our competitors' costs, such as operators of nuclear generation, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain of our states have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements (including Ohio, Michigan, Texas and Virginia). We are taking steps to comply with these requirements. In order to meet these requirements and as a key part of our corporate sustainability effort, we pledged to increase our wind power by an additional 2,000 MW from 2007 levels by 2011. By the end of 2009, we secured through power purchase agreements an additional 1,013 MW of wind power. To the extent demand for renewable energy from wind power increases, it could have a positive effect on future earnings from our transmission activities. For example, a project in Texas would build new transmission lines to transport electricity from planned wind energy generation in west Texas to more densely populated areas in eastern Texas.

We have taken measurable, voluntary actions to reduce and offset our CO_2 emissions. We participate in a number of voluntary programs to monitor, mitigate and reduce CO_2 emissions, including the Federal EPA's Climate Leaders program, the United States Department of Energy's CO_2 reporting program and the Chicago Climate Exchange. Through the end of 2008, we reduced our emissions by a cumulative 51 million metric tons from adjusted baseline levels in 1998 through 2001 as a result of these voluntary actions. Our total CO_2 emissions in 2008 were 155 million metric tons. We estimate that our 2009 emissions were approximately 140 million metric tons. Since 2004, our cumulative reductions will be in excess of 70 million metric tons.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 6.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 would result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could have a material adverse impact on our net income, cash flows and financial condition.

Global warming creates the potential for physical and financial risk. The materiality of the risks depends on whether any physical changes occur quickly or over several decades and the extent and nature of those changes. Physical risks from climate change could include changes in weather conditions. Our customers' energy needs currently vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling today represent their largest energy use. To the extent weather patterns change significantly, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Increased energy use due to weather changes could require us to invest in more generating assets, transmission and other infrastructure to serve increased load, driving the overall cost of electricity up. Decreased energy use due to weather changes could affect our financial condition through lower sales and decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions and increased storm restoration costs. We may not recover all costs related to mitigating these physical and financial risks. Weather conditions outside of our service territory could also have an impact on our revenues, either directly through changes in the patterns of our off-system power purchases and sales or indirectly through demographic changes as people adapt to changing weather. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions that create high energy demand could raise electricity prices, which could increase the cost of energy we provide to our customers and could provide opportunity for increased wholesale sales.

To the extent climate change impacts a region's economic health, it could also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider 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 net income or financial condition.

We discuss 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.

We believe 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 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 incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Examples of new events include 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 net income. Refer to Note 5 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 perform 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. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electric utility revenues included in Revenue on our Consolidated Statements of Income were $55 million, $72 million and $47 million for the years ended December 31, 2009, 2008 and 2007, respectively. The increases in unbilled electric revenues are primarily due to rate increases and changes in weather. Accrued unbilled revenues for the Utility Operations segment were $503 million and $448 million as of December 31, 2009 and 2008, respectively.

Assumptions and Approach Used

For each operating company, we compute 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 meter reading issues, 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, 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 Consolidated Balance Sheets.

Accounting for Derivative Instruments

Nature of Estimates Required

We consider 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 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 settle.

The probability that hedged forecasted transactions will not 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 derivatives, hedging and fair value measurements, see Notes 10 and 11. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, 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. We utilize a group composite method of depreciation to estimate the useful lives of long-lived assets. 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 Used

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 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. We perform depreciation studies to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions. 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 "Property, Plant and Equipment" accounting guidance, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. The estimate for depreciation rates takes into account the past history of interim capital replacements and the amount of salvage expected. In cases of impairment, we made our best estimate of fair value using valuation methods based on the most current information at that time. 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 our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

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 (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law to be paid to participants in the Qualified Plans (collectively the Pension Plans). We merged the Qualified Plans at December 31, 2008. Additionally, we entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 8 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost of the Plans:

Net Periodic Benefit Cost	Years Ended December 31, 2009	2008	2007
		(in millions)	
Pension Plans	$ 96	$ 51	$ 50
Postretirement Plans	141	80	81

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2010, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets as well as our ten-year average return, for the period ended December 2009, of approximately 3.7% for the Pension Plans and approximately 2.3% for the Postretirement Plans. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 8% for the Pension Plan and Postretirement Plans.

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 Plans		Other Postretirement Benefit Plans	
	2010 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return	2010 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return
Equity	50%	9.50%	66%	9.75%
Real Estate	5%	7.25%	-%	-%
Debt Securities	39%	6.00%	33%	6.00%
Other Investments	5%	10.00%	-%	-%
Cash and Cash Equivalents	1%	3.00%	1%	3.00%
Total	100%		100%	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 8% for the Pension Plans and Postretirement Plans are reasonable long-term rates of return on the Plans' assets despite the recent market volatility. The Pension Plans' assets had an actual gain (loss) of 17.1% and (24.1)% for the years ended December 31, 2009 and 2008, respectively. The Postretirement Plans' assets had an actual gain (loss) of 23.7% and (24.7)% for the years ended December 31, 2009 and 2008, 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, 2009, we had cumulative losses of approximately $600 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses will result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

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, 2009 under this method was 5.6% for the Qualified Plan, 5.5% for the Nonqualified 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%, a discount rate of 5.6% and 5.5% and various other assumptions, we estimate that the pension costs for all pension plans will approximate $163 million, $166 million and $186 million in 2010, 2011 and 2012, respectively. Based on an expected rate of return on the OPEB plans' assets of 8%, a discount rate of 5.85% and various other assumptions, we estimate Postretirement Plan costs will approximate $112 million, $94 million and $77 million in 2010, 2011 and 2012, 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 the "Effect if Different Assumptions Used" section below.

The value of the Pension Plans' assets increased to $3.4 billion at December 31, 2009 from $3.2 billion at December 31, 2008 primarily due to investment gains. The Qualified Plans paid $240 million in benefits to plan participants during 2009 (nonqualified plans paid $8 million in benefits). The value of our Postretirement Plans' assets increased to $1.3 billion at December 31, 2009 from $1 billion at December 31, 2008 primarily due to investment gains and contributions. The Postretirement Plans paid $120 million in benefits to plan participants during 2009.

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 "Compensation" and "Plan Accounting" accounting guidance. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

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

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. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. 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 Benefit Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2009 Benefit Obligations				
Discount Rate	$ (231)	$ 253	$ (119)	$ 133
Compensation Increase Rate	15	(14)	3	(3)
Cash Balance Crediting Rate	45	(39)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	96	(87)
Effect on 2009 Periodic Cost				
Discount Rate	(20)	22	(11)	11
Compensation Increase Rate	4	(4)	-	(1)
Cash Balance Crediting Rate	10	(9)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	15	(14)
Expected Return on Plan Assets	(20)	20	(5)	5

N/A = Not Applicable

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.

We maintain trust funds for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested 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 these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at fair value. We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in these trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. See "Investments Held in Trust for Future Liabilities" section of Note 1 and "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11.

NEW ACCOUNTING PRONOUNCEMENTS

Adoption of New Accounting Pronouncements in 2009

The FASB issued SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160), modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. We retrospectively adopted the presentation and disclosure requirements of SFAS 160.

New Accounting Pronouncements Adopted During the First Quarter of 2010

We prospectively adopted SFAS 166 "Accounting for Transfers of Financial Assets" (SFAS 166) effective January 1, 2010. The adoption of this standard resulted in AEP Credit's transfer of receivables being accounted for as financings with the receivable and debt recorded on our balance sheet.

We prospectively adopted SFAS 167 "Amendments to FASB Interpretation No. 46(R)" (SFAS 167) effective January 1, 2010. We no longer consolidate DHLC effective with the adoption of this standard.

See Note 2 for further discussion of accounting pronouncements.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, 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 revenue recognition, contingencies, financial instruments, emission allowances, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. 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 net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET AND CREDIT RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. 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.

Our Generation and Marketing segment, operating primarily within ERCOT, transacts in wholesale energy trading and marketing contracts. This segment is exposed to certain market risks as a marketer of wholesale electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

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

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of electricity, coal, natural gas and emission allowances 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 approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our Executive Vice President - Generation, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2009
(in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2008	$ 175	$ 104	$ (7)	$ 272
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(99)	(7)	5	(101)
Fair Value of New Contracts at Inception When Entered During the Period (a)	14	63	-	77
Changes in Fair Value Due to Market Fluctuations During the Period (b)	5	(13)	(1)	(9)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	39	-	-	39
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2009	$ 134	$ 147	$ (3)	278
Cash Flow Hedge Contracts				(9)
Collateral Deposits				86
Total MTM Derivative Contract Net Assets at December 31, 2009				$ 355

(a) Reflects fair value on long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, 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 liabilities/assets.

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our wholesale 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 originated. We use Moody's Investors Service, Standard & Poor's and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating. Based on our analysis, we set appropriate risk parameters for each internally-graded counterparty. We may also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties in order to mitigate credit risk.

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. At December 31, 2009, our credit exposure net of collateral to sub investment grade counterparties was approximately 12.2%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2009, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 653	$ 44	$ 609	2	$ 186
Split Rating	3	-	3	1	3
Noninvestment Grade	2	1	1	3	1
No External Ratings:					
Internal Investment Grade	82	2	80	3	48
Internal Noninvestment Grade	106	11	95	3	79
Total as of December 31, 2009	$ 846	$ 58	$ 788	12	$ 317
Total as of December 31, 2008	$ 793	$ 29	$ 764	9	$ 284

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates 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, 2009, a near term typical change in commodity prices is not expected to have a material effect on our net income, 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, 2009 (in millions)				December 31, 2008 (in millions)			
End	High	Average	Low	End	High	Average	Low
$1	$2	$1	$-	$-	$3	$1	$-

We back-test our VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Our backtesting results show that our actual performance exceeded VaR far fewer than once every 20 trading days. As a result, we believe our VaR calculation is conservative.

As our VaR calculation captures recent price moves, we also perform regular stress testing of the portfolio to understand our exposure to extreme price moves. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last four years in order to ascertain which historical price moves translated into the largest potential MTM loss. We then research the underlying positions, price moves and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the CORC as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which AEP's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2009 and 2008, the estimated EaR on our debt portfolio for the following twelve months was $4 million and $86 million, respectively.

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, 2009 and 2008, and the related consolidated statements of income, changes in equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the accompanying consolidated financial statements were retrospectively adjusted to reflect the adoption of FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, 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 26, 2010 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Columbus, Ohio
February 26, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2009, 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, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, 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, 2009 of the Company and our report dated February 26, 2010 expressed an unqualified opinion on those financial statements and included an explanatory paragraph concerning the Company's adoption ofa new accounting pronouncement

Deloitte & Touche LLP

Columbus, Ohio
February 26, 2010

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.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2009. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2009.

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

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2009, 2008 and 2007
(in millions, except per-share and share amounts)

REVENUES	2009	2008	2007
Utility Operations	$ 12,733	$ 13,326	$ 12,101
Other Revenues	756	1,114	1,279
TOTAL REVENUES	13,489	14,440	13,380
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	3,478	4,474	3,829
Purchased Electricity for Resale	1,053	1,281	1,138
Other Operation	2,620	2,856	2,664
Maintenance	1,205	1,053	1,162
Gain on Settlement of TEM Litigation	-	(255)	-
Depreciation and Amortization	1,597	1,483	1,513
Taxes Other Than Income Taxes	765	761	755
TOTAL EXPENSES	10,718	11,653	11,061
OPERATING INCOME	2,771	2,787	2,319
Other Income (Expense):			
Interest and Investment Income	11	57	51
Carrying Costs Income	47	83	51
Allowance for Equity Funds Used During Construction	82	45	33
Gain on Disposition of Equity Investments	-	-	47
Interest Expense	(973)	(957)	(838)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	1,938	2,015	1,663
Income Tax Expense	575	642	516
Equity Earnings of Unconsolidated Subsidiaries	7	3	6
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	1,370	1,376	1,153
DISCONTINUED OPERATIONS, NET OF TAX	-	12	24
INCOME BEFORE EXTRAORDINARY LOSS	1,370	1,388	1,177
EXTRAORDINARY LOSS, NET OF TAX	(5)	-	(79)
NET INCOME	1,365	1,388	1,098
Less: Net Income Attributable to Noncontrolling Interests	5	5	6
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,360	1,383	1,092
Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,357	$ 1,380	$ 1,089
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	458,677,534	402,083,847	398,784,745
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.97	$ 3.40	$ 2.87
Discontinued Operations, Net of Tax	-	0.03	0.06
Income Before Extraordinary Loss	2.97	3.43	2.93
Extraordinary Loss, Net of Tax	(0.01)	-	(0.20)
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.96	$ 3.43	$ 2.73
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	458,982,292	403,640,708	400,198,799
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.97	$ 3.39	$ 2.86
Discontinued Operations, Net of Tax	-	0.03	0.06
Income Before Extraordinary Loss	2.97	3.42	2.92
Extraordinary Loss, Net of Tax	(0.01)	-	(0.20)
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.96	$ 3.42	$ 2.72
CASH DIVIDENDS PAID PER SHARE	$ 1.64	$ 1.64	$ 1.58

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2009, 2008 and 2007
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2006	418	$ 2,718	$ 4,221	$ 2,696	$ (223)	$ 18	$ 9,430
Adoption of Guidance for Uncertainty in Income Taxes, Net of Tax				(17)			(17)
Issuance of Common Stock	4	25	119				144
Common Stock Dividends				(630)		(6)	(636)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			12				12
SUBTOTAL – EQUITY							8,930
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $10					(20)		(20)
Securities Available for Sale, Net of Tax of $1					(1)		(1)
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $6					11		11
Pension and OPEB Funded Status, Net of Tax of $42					79		79
NET INCOME				1,092		6	1,098
TOTAL COMPREHENSIVE INCOME							1,167
TOTAL EQUITY – DECEMBER 31, 2007	422	2,743	4,352	3,138	(154)	18	10,097
Adoption of Guidance for Split-Dollar Life Insurance Accounting, Net of Tax of $6				(10)			(10)
Adoption of Guidance for Fair Value Accounting, Net of Tax of $0				(1)			(1)
Issuance of Common Stock	4	28	131				159
Reissuance of Treasury Shares			40				40
Common Stock Dividends				(660)		(6)	(666)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			4				4
SUBTOTAL – EQUITY							9,620
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $2					4		4
Securities Available for Sale, Net of Tax of $9					(16)		(16)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $7					12		12
Pension and OPEB Funded Status, Net of Tax of $161					(298)		(298)
NET INCOME				1,383		5	1,388
TOTAL COMPREHENSIVE INCOME							1,090
TOTAL EQUITY – DECEMBER 31, 2008	426	2,771	4,527	3,847	(452)	17	10,710
Issuance of Common Stock	72	468	1,311				1,779
Common Stock Dividends				(753)		(5)	(758)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Purchase of JMG			37			(18)	19
Other Changes in Equity			(51)			1	(50)
SUBTOTAL – EQUITY							11,697
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $4					7		7
Securities Available for Sale, Net of Tax of $6					11		11
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $8					15		15
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $13					23		23
Pension and OPEB Funded Status, Net of Tax of $12					22		22
NET INCOME				1,360		5	1,365
TOTAL COMPREHENSIVE INCOME							1,443
TOTAL EQUITY – DECEMBER 31, 2009	498	$ 3,239	$ 5,824	$ 4,451	$ (374)	$ -	$ 13,140

See Notes to Consolidated Financial Statements

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2009 and 2008
(in millions)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 490	$ 411
Other Temporary Investments	363	327
Accounts Receivable:		
Customers	492	569
Accrued Unbilled Revenues	503	449
Miscellaneous	92	90
Allowance for Uncollectible Accounts	(37)	(42)
Total Accounts Receivable	1,050	1,066
Fuel	1,075	634
Materials and Supplies	586	539
Risk Management Assets	260	256
Accrued Tax Benefits	547	46
Regulatory Asset for Under-Recovered Fuel Costs	85	284
Margin Deposits	89	86
Prepayments and Other Current Assets	211	126
TOTAL CURRENT ASSETS	4,756	3,775
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	23,045	21,242
Transmission	8,315	7,938
Distribution	13,549	12,816
Other Property, Plant and Equipment (including coal mining and nuclear fuel)	3,744	3,741
Construction Work in Progress	3,031	3,973
Total Property, Plant and Equipment	51,684	49,710
Accumulated Depreciation and Amortization	17,340	16,723
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	34,344	32,987
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,595	3,783
Securitized Transition Assets	1,896	2,040
Spent Nuclear Fuel and Decommissioning Trusts	1,392	1,260
Goodwill	76	76
Long-term Risk Management Assets	343	355
Deferred Charges and Other Noncurrent Assets	946	879
TOTAL OTHER NONCURRENT ASSETS	9,248	8,393
TOTAL ASSETS	$ 48,348	$ 45,155

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2009 and 2008

	2009	2008
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 1,158	$ 1,297
Short-term Debt	126	1,976
Long-term Debt Due Within One Year	1,741	447
Risk Management Liabilities	120	134
Customer Deposits	256	254
Accrued Taxes	632	634
Accrued Interest	287	270
Regulatory Liability for Over-Recovered Fuel Costs	76	66
Other Current Liabilities	931	1,219
TOTAL CURRENT LIABILITIES	5,327	6,297
NONCURRENT LIABILITIES		
Long-term Debt	15,757	15,536
Long-term Risk Management Liabilities	128	170
Deferred Income Taxes	6,420	5,128
Regulatory Liabilities and Deferred Investment Tax Credits	2,909	2,789
Asset Retirement Obligations	1,254	1,154
Employee Benefits and Pension Obligations	2,189	2,184
Deferred Credits and Other Noncurrent Liabilities	1,163	1,126
TOTAL NONCURRENT LIABILITIES	29,820	28,087
TOTAL LIABILITIES	35,147	34,384
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2009	2008
Shares Authorized	600,000,000	600,000,000
Shares Issued	498,333,265	426,321,248

	2009	2008
(20,278,858 shares and 20,249,992 shares were held in treasury at December 31, 2009 and 2008, respectively)	3,239	2,771
Paid-in Capital	5,824	4,527
Retained Earnings	4,451	3,847
Accumulated Other Comprehensive Income (Loss)	(374)	(452)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	13,140	10,693
Noncontrolling Interests	-	17
TOTAL EQUITY	13,140	10,710
TOTAL LIABILITIES AND EQUITY	$ 48,348	$ 45,155

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, 2009, 2008 and 2007
(in millions)

	2009	2008	2007
OPERATING ACTIVITIES			
Net Income	$ 1,365	$ 1,388	$ 1,098
Less: Discontinued Operations, Net of Tax	-	(12)	(24)
Income Before Discontinued Operations	1,365	1,376	1,074
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,597	1,483	1,513
Deferred Income Taxes	1,244	498	76
Provision for SIA Refund	-	149	-
Extraordinary Loss, Net of Tax	5	-	79
Carrying Costs Income	(47)	(83)	(51)
Allowance for Equity Funds Used During Construction	(82)	(45)	(33)
Mark-to-Market of Risk Management Contracts	(59)	(140)	3
Amortization of Nuclear Fuel	63	88	65
Pension and Postemployment Benefits	83	42	41
Property Taxes	(17)	(13)	(26)
Fuel Over/Under-Recovery, Net	(474)	(272)	(117)
Gains on Sales of Assets, Net	(15)	(17)	(88)
Change in Noncurrent Liability for NSR Settlement	-	-	58
Change in Other Noncurrent Assets	(137)	(244)	(142)
Change in Other Noncurrent Liabilities	161	(34)	66
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	41	71	(113)
Fuel, Materials and Supplies	(475)	(183)	16
Margin Deposits	(3)	(40)	50
Accounts Payable	8	(94)	(21)
Customer Deposits	2	(48)	49
Accrued Taxes, Net	(470)	4	(90)
Accrued Interest	17	30	11
Other Current Assets	(70)	(29)	(11)
Other Current Liabilities	(262)	82	(15)
Net Cash Flows from Operating Activities	2,475	2,581	2,394
INVESTING ACTIVITIES			
Construction Expenditures	(2,792)	(3,800)	(3,556)
Change in Other Temporary Investments, Net	16	45	(114)
Purchases of Investment Securities	(853)	(1,922)	(11,086)
Sales of Investment Securities	748	1,917	11,213
Acquisitions of Nuclear Fuel	(169)	(192)	(74)
Acquisitions of Assets	(104)	(160)	(512)
Proceeds from Sales of Assets	278	90	222
Other Investing Activities	(40)	(5)	(14)
Net Cash Flows Used for Investing Activities	(2,916)	(4,027)	(3,921)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	1,728	159	144
Issuance of Long-term Debt	2,306	2,774	2,546
Borrowings from Revolving Credit Facilities	127	2,055	85
Change in Short-term Debt, Net	119	(660)	659
Retirement of Long-term Debt	(816)	(1,824)	(1,286)
Repayments to Revolving Credit Facilities	(2,096)	(79)	(102)
Proceeds from Nuclear Fuel Sale/Leaseback	-	-	85
Principal Payments for Capital Lease Obligations	(82)	(97)	(67)
Dividends Paid on Common Stock	(758)	(666)	(636)
Dividends Paid on Cumulative Preferred Stock	(3)	(3)	(3)
Other Financing Activities	(5)	20	(21)
Net Cash Flows from Financing Activities	520	1,679	1,404
Net Increase (Decrease) in Cash and Cash Equivalents	79	233	(123)
Cash and Cash Equivalents at Beginning of Period	411	178	301
Cash and Cash Equivalents at End of Period	$ 490	$ 411	$ 178

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 seven of our electric utility operating companies is the generation, transmission and distribution of electric power. TCC exited the generation business and along with KGPCo and WPCo, provide only transmission and distribution services. TNC engages in the transmission and distribution of electric power and is a part owner in the Oklaunion Plant operated by PSO. TNC leases their entire portion of the output of the plant through 2027 to a nonutility affiliate. 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 the 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 wind farms and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The FERC also regulates our affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires that a nonregulated affiliate can bill an affiliated public utility company no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions in Virginia and West Virginia also regulate certain intercompany transactions under their affiliate statutes.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based. They are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We have entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually. Our wholesale power transactions in the SPP region are cost-based due to PSO and SWEPCo having market power in the SPP region.

The state regulatory commissions regulate all of the distribution operations and rates of our retail public utilities on a cost basis. They also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. The ESP rates in Ohio continue the process of increasing generation/power supply rates over time to approach market rates. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing and is conducted by REPs. Through its nonregulated subsidiaries, AEP enters into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT. Effective November 2009, AEP had no active REPs in ERCOT. SWEPCo operates in the SPP area which includes a portion of Texas. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations. In 2007, Virginia legislation ended a transition to market-based rates and returned APCo's retail generation/supply business to cost-based regulation.

The FERC also regulates our wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. CSPCo's and OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia, I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled. CSPCo's and OPCo's retail transmission rates in Ohio and APCo's retail transmission rates in Virginia are based on the FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Although I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the state regulatory commissions. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement, the Transmission Coordination Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement.

Both the 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 our wholly-owned and majority-owned subsidiaries and variable interest entities (VIEs) of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. We use the equity method of accounting for equity investments where we exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Income. For years, we have had ownership interests in 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.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. We believe that significant assumptions and judgments were applied consistently. Also, see "SFAS 167 'Amendments to FASB Interpretation No. 46(R)' " section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010.

We are currently the primary beneficiary of Sabine, DHLC, DCC Fuel LLC (DCC Fuel) and a protected cell of EIS. We were the primary beneficiary of JMG through December 15, 2009 when the lease was cancelled and all assets and liabilities of JMG were transferred to OPCo. We hold a significant variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series). In addition, we have not provided material financial or other support to Sabine, DHLC, DCC Fuel or our protected cell of EIS that was not previously contractually required. Refer to the discussion of JMG below for details regarding payments that were not contractually required and for the subsequent transfer of JMG's assets and liabilities to OPCo.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. Based on these facts, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2009 and 2008 were $99 million and $110 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Consolidated Balance Sheets.

DHLC is a wholly-owned subsidiary of SWEPCo. DHLC is a mining operator that sells 50% of the lignite produced to SWEPCo and 50% to Cleco Corporation, a nonaffiliated company. SWEPCo and Cleco Corporation share half of the executive board seats, with equal voting rights and each entity guarantees a 50% share of DHLC's debt. SWEPCo and Cleco Corporation equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC it receives 100% of the management fee. Based on the structure and equity ownership, management has concluded that SWEPCo is the primary beneficiary and is currently required to consolidate DHLC. In December 2009, SWEPCo provided additional capital to DHLC in the amount of $5 million. SWEPCo's total billings from DHLC for the years ended December 31, 2009 and 2008 were $43 million and $44 million, respectively. See the tables below for the classification of DHLC assets and liabilities on our Consolidated Balance Sheets. Also, see "SFAS 167 'Amendments to FASB Interpretation No. 46(R)' " section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010.

OPCo had a lease agreement with JMG to finance OPCo's FGD system installed on OPCo's Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG owned and leased the FGD to OPCo. JMG was considered a single-lessee leasing arrangement with only one asset. OPCo's lease payments were the only form of repayment associated with JMG's debt obligations even though OPCo did not guarantee JMG's debt. The creditors of JMG had no recourse to any AEP entity other than OPCo for the lease payment. Based on the structure of the entity, management had concluded OPCo was the primary beneficiary and was required to consolidate JMG. In April 2009, OPCo paid JMG $58 million which was used to retire certain long-term debt of JMG. While this payment was not contractually required, OPCo made this payment in anticipation of purchasing the outstanding equity of JMG. In July 2009, OPCo purchased all of the outstanding equity ownership of JMG for $28 million resulting in an elimination of OPCo's Noncontrolling Interest related to JMG and an increase in equity of $37 million. In August and September 2009, JMG reacquired $218 million of auction rate debt, funded by OPCo capital contributions to JMG. These reacquisitions were not contractually required. In December 2009, the lease was cancelled and all the assets and liabilities of JMG were transferred to OPCo. OPCo's total billings under the lease term from JMG for the years ended December 31, 2009 and 2008 were $66 million and $57 million, respectively. See the tables below for the classification of JMG's assets and liabilities on our Consolidated Balance Sheets.

EIS has multiple protected cells in which our subsidiaries participate in one protected cell for approximately ten lines of insurance. Neither AEP nor its subsidiaries have an equity investment of EIS. The AEP system is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on the structure of the protected cell and EIS, management has concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the years ended December 31, 2009 and 2008 were $30 million and $28 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on our Consolidated Balance Sheets. Note the amount reported as equity is the protected cell's policy holders' surplus.

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel. DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. DCC Fuel is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Payments on the lease will be made semi-annually on April 1 and October 1, beginning in April 2010. As of December 31, 2009, no payments have been made by I&M to DCC Fuel. The lease was recorded as a capital lease on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48 month lease term. Based on the structure, management has concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital lease is eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on our Consolidated Balance Sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2009
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	I&M DCC Fuel	Protected Cell of EIS
ASSETS					
Current Assets	$ 51	$ 8	$ -	$ 47	$ 130
Net Property, Plant and Equipment	149	44	-	89	-
Other Noncurrent Assets	35	11	-	57	2
Total Assets	$ 235	$ 63	$ -	$ 193	$ 132
LIABILITIES AND EQUITY					
Current Liabilities	$ 36	$ 17	$ -	$ 39	$ 36
Noncurrent Liabilities	199	38	-	154	74
Equity	-	8	-	-	22
Total Liabilities and Equity	$ 235	$ 63	$ -	$ 193	$ 132

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2008
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	I&M DCC Fuel	Protected Cell of EIS
ASSETS					
Current Assets	$ 33	$ 22	$ 11	$ -	$ 107
Net Property, Plant and Equipment	117	33	423	-	-
Other Noncurrent Assets	24	11	1	-	2
Total Assets	$ 174	$ 66	$ 435	$ -	$ 109
LIABILITIES AND EQUITY					
Current Liabilities	$ 32	$ 18	$ 161	$ -	$ 30
Noncurrent Liabilities	142	44	257	-	60
Equity	-	4	17	-	19
Total Liabilities and Equity	$ 174	$ 66	$ 435	$ -	$ 109

In September 2007, we and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the "Ohio Series," the "West Virginia Series (PATH-WV)," both owned equally by AYE and AEP and the "Allegheny Series" which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The "Ohio Series" does not include the same provisions that make PATH-WV a VIE. Neither the "Ohio Series" or "Allegheny Series" are considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE's subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series should be consistent with other regulated utilities. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. The likelihood of such a loss is remote since the FERC approved PATH-WV's request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV was:

	December 31,			
	2009		2008	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from Parent	$ 13	$ 13	$ 4	$ 4
Retained Earnings	3	3	2	2
Total Investment in PATH-WV	$ 16	$ 16	$ 6	$ 6

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," we record regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) 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 passage of legislation requiring restructuring and a transition to customer choice and market-based rates, we discontinued the application of "Regulated Operations" accounting treatment for the generation portion of our business in Ohio for CSPCo and OPCo and in Texas for TNC. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations. In 2007, the Virginia legislature also amended its restructuring legislation to provide for the re-regulation of generation and supply business and rates on a cost basis, which resulted in the re-application of accounting guidance for "Regulated Operations" for APCo's Virginia generation operations.

Accounting guidance for "Discontinuation of Rate-Regulated Operations" requires the recognition of an impairment of stranded net regulatory assets and stranded plant costs if they are not recoverable in regulated rates. In addition, an enterprise is required to eliminate from its balance sheet the effects of any actions of regulators that had been recognized as regulatory assets and regulatory liabilities. Such impairments and adjustments are classified as an extraordinary item. Consistent with accounting guidance for "Discontinuation of Rate-Regulated Operations," APCo and SWEPCo recorded extraordinary reductions in earnings and shareholder's equity from the reapplication of "Regulated Operations" accounting guidance in 2007 and 2009, respectively.

Use of Estimates

The preparation of these financial statements in conformity with 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.

Cash and Cash Equivalents

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

Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell of EIS 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 "Investments – Debt and Equity Securities" accounting guidance. We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary 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.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See "Fair Value Measurements of Other Temporary Investments" in Note 11.

Inventory

Fossil fuel inventories are generally carried at average cost. 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 sales when we deliver power 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, excluding receivables from risk management activities, for certain subsidiaries. The subsidiaries include CSPCo, I&M, KGPCo, 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 bank conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the bank conduits and receives cash. This transaction constitutes a sale of receivables in accordance with the accounting guidance effective during 2009 for "Transfers and Servicing," allowing the receivables to be removed from the company's balance sheet (see "Sale of Receivables – AEP Credit" section of Note 14). Also, see "SFAS 166 'Accounting for Transfers of Financial Assets' " section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010.

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 these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Deferred Charges and Other Noncurrent Assets 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 Prepayments and 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. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

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 equity investments (included in Deferred Charges and Other Noncurrent Assets) are stated at fair 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 the Utility Operations segment, normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for both cost-based rate-regulated and most nonregulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. For the nonregulated generation assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Gains and losses are recorded for any retirements in the AEP River Operations and Generation and Marketing segments. Removal costs are charged to regulatory liabilities for cost-based rate-regulated operations and charged to expense for nonregulated operations. 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 the accounting guidance for "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 regulated electric utility plant. For nonregulated operations, including generating assets in Ohio and Texas, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

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.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the benefit plan and nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the plans. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana (beginning in July 2007) and Michigan for I&M, in Texas, Louisiana and Arkansas for SWEPCo, in Oklahoma for PSO and in Virginia and West Virginia (prior to 2009) for APCo are reflected in rates in a timely manner through the FAC. Beginning in 2009, changes in fuel costs, including purchased power in Ohio for CSPCo and OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. All of the profits from off-system sales are shared with customers through the FAC in West Virginia for APCo. A portion of profits from off-system sales are shared with customers through the FAC and other rate mechanisms in Oklahoma for PSO, Texas, Louisiana and Arkansas for SWEPCo, Kentucky for KPCo, Virginia (beginning in September 2007) for APCo and in Indiana (beginning in July 2007) and some areas of Michigan for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent (prior to July 2007 for I&M in Indiana, prior to 2009 for CSPCo and OPCo in Ohio and currently in Texas for AEP Energy Partners, Inc.), changes in fuel costs or sharing of off-system sales impacted earnings.

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) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

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 at each balance sheet date or whenever new events occur. Examples of new events include the 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 income.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity 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.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. We purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as revenues on our Consolidated Statements of Income. However, in 2009, there were times when we were a purchaser of power from PJM to serve retail load. These purchases were recorded gross as Purchased Electricity for Resale on our Consolidated Statements of Income. Other RTOs in which we operate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases, including those from RTOs, that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Electricity for Resale on our Consolidated Statements of Income.

In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. 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, we defer all unrealized gains and losses as regulatory liabilities for net gains or regulatory assets for net losses that result from measuring these contracts at fair value during the period before settlement. If the contract results in the physical delivery of power from a RTO or any other counterparty, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts gross as Purchased Electricity for Resale. If the contract does not result in physical delivery, 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 Note 10).

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 and adjacent markets. 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, as well as over-the-counter options and swaps. We engage in certain energy marketing and risk management transactions with RTOs.

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 hedge relationship or 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 and some realized gains and losses 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 qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, we subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on our Consolidated Statements of Income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on our Consolidated Statements of Income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains) (see "Accounting for Cash Flow Hedging Strategies" section of Note 10).

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage 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 our computerized barge tracking system.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

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 distribution tree trimming costs for PSO above the level included in base rates and amortize those deferrals commensurate with recovery through a rate rider in Oklahoma.

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.

We account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." We classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation.

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 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 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.

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 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 10 to 15 years, to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

We have several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are diversified and managed in compliance with all laws and regulations. Our investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the 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 targeted allocation when appropriate. 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. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for our benefit plans support the allocation of assets to minimize risks and optimizing net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable level.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The target asset allocation and allocation ranges are as follows:

Pension Plan Assets	Minimum	Target	Maximum
Domestic Equity	30.0%	35.0%	40.0%
International and Global Equity	10.0%	15.0%	20.0%
Fixed Income	35.0%	39.0%	45.0%
Real Estate	4.0%	5.0%	6.0%
Other Investments	1.0%	5.0%	7.0%
Cash	0.5%	1.0%	3.0%

OPEB Plans Assets	Minimum	Target	Maximum
Equity	61.0%	66.0%	71.0%
Fixed Income	29.0%	33.0%	37.0%
Cash	1.0%	1.0%	4.0%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities. Investment policies prohibit the benefit trust funds from purchasing securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, our investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- Individual stock must be less than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in one issuer
- 20% in non-US dollar denominated
- 5% private placements
- 5% convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return, and hedge against inflation. Real estate properties are illiquid, difficult to value, and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type, and risk classification. Real estate holdings include core, value-added, and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value, and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. Our private equity holdings are with six general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout, and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

We participate in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. We lend securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

We hold trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable VEBA trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

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 when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust records for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested 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 these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at fair value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. When a security's fair value is less than its cost basis, we recognize an impairment as we do not make specific investment decisions regarding the assets held in these trusts. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. We record unrealized gains 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 the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

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)(AOCI)

AOCI is included on our Consolidated Balance Sheets in our equity section. The following table provides the components that constitute the balance sheet amount in AOCI:

Components	December 31, 2009	December 31, 2008
	(in millions)	
Securities Available for Sale, Net of Tax	$ 12	$ 1
Cash Flow Hedges, Net of Tax	(15)	(22)
Amortization of Pension and OPEB Deferred Costs, Net of Tax	35	12
Pension and OPEB Funded Status, Net of Tax	(406)	(443)
Total	$ (374)	$ (452)

Stock-Based Compensation Plans

At December 31, 2009, 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 last approved by shareholders 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. Dividends paid on career shares are reinvested as additional career shares.

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 become payable in cash to directors after their service 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 common stock.

In January 2006, we adopted accounting guidance for "Share-Based Payment" which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options, based on estimated fair values.

We recognize compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. In 2009, 2008 and 2007, we granted awards with performance conditions which are expensed on the accelerated multiple-option approach. Stock-based compensation expense recognized on our Consolidated Statements of Income for the years ended December 31, 2009, 2008 and 2007 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Share-Based Payment" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2009, 2008 and 2007, 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 15 for additional discussion.

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:

	Years Ended December 31,					
	2009		2008		2007	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,357		$ 1,380		$ 1,089	
Weighted Average Number of Basic Shares Outstanding	458.7	$ 2.96	402.1	$ 3.43	398.8	$ 2.73
Weighted Average Dilutive Effect of:						
Performance Share Units	0.3	-	1.2	0.01	0.9	0.01
Stock Options	-	-	0.1	-	0.3	-
Restricted Stock Units	-	-	0.1	-	0.1	-
Restricted Shares	-	-	0.1	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	459.0	$ 2.96	403.6	$ 3.42	400.2	$ 2.72

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

Options to purchase 452,216, 470,016 and 83,150 shares of common stock were outstanding at December 31, 2009, 2008 and 2007, respectively, but were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the year-end market price of the common shares, the effect would be antidilutive.

CSPCo and OPCo Revised Depreciation Rates

Effective January 1, 2009, we revised book depreciation rates for CSPCo and OPCo generating plants consistent with a recently completed depreciation study. OPCo's overall higher depreciation rates primarily related to shortened depreciable lives for certain OPCo generating facilities. In comparing 2009 and 2008, the change in depreciation rates resulted in a net increase (decrease) in depreciation expense of:

	Depreciation Expense Variance
	Years Ended December 31, 2009/2008
	(in millions)
CSPCo	$ (18)
OPCo	71

The net change in depreciation rates resulted in a decrease to our net-of-tax, basic earnings per share of $0.08 for the year ended December 31, 2009.

Supplementary Information

Related Party Transactions	Years Ended December 31, 2009	2008	2007
		(in millions)	
AEP Consolidated Revenues – Utility Operations:			
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% Owned) (a)	$ -	$ (54)	$ (29)
AEP Consolidated Revenues – Other Revenues:			
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	31	32	31
AEP Consolidated Expenses – Purchased Electricity for Resale:			
Ohio Valley Electric Corporation (43.47% Owned)	286	263	226
Sweeny Cogeneration Limited Partnership (b)	-	-	86

(a) In 2006, the AEP Power Pool began purchasing power from OVEC as part of risk management activities. The agreement ended in December 2008.
(b) In October 2007, we sold our 50% ownership in the Sweeny Cogeneration Limited Partnership. See "Sweeny Cogeneration Plant" section of Note 7.

Amounts Attributable To AEP Common Shareholders	Years Ended December 31, 2009	2008	2007
		(in millions)	
Income Before Discontinued Operations and Extraordinary Loss, Net of Tax	$ 1,362	$ 1,368	$ 1,144
Discontinued Operations, Net of Tax	-	12	24
Extraordinary Loss, Net of Tax	(5)	-	(79)
Net Income	$ 1,357	$ 1,380	$ 1,089

Cash Flow Information	Years Ended December 31, 2009	2008	2007
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 924	$ 853	$ 734
Income Taxes	(98)	233	576
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	86	62	160
Assumption of Liabilities Related to Acquisitions/Divestitures, Net	-	-	8
Disposition of Assets Related to Electric Transmission Texas Joint Venture	-	-	(14)
Construction Expenditures Included in Accounts Payable at December 31,	348	460	345
Acquisition of Nuclear Fuel Included in Accounts Payable at December 31,	-	38	84
Noncash Donation Expense Related to Issuance of Treasury Shares to AEP Foundation	-	40	-

Transmission Investments

We participate in certain joint ventures which involve the development, construction, ownership and operation of transmission facilities. These investments are recorded using the equity method and reported as Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets.

Power Projects

During 2007, we sold our 50% interest in Sweeny, a nonregulated power plant with a capacity of 480 MW located in Texas. 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 Noncurrent Assets on our Consolidated Balance Sheets.

Reclassifications

In the Financing Activities section of our Consolidated Statements of Cash Flows for the years ended December 31, 2008 and 2007, we corrected the presentation of borrowings on our lines of credit of $2.1 billion and $85 million, respectively, from Change in Short-term Debt, Net to Borrowings from Revolving Credit Facilities. We also corrected the presentation of repayments on our lines of credit of $79 million and $102 million for the years ended December 31, 2008 and 2007, respectively, to Repayments to Revolving Credit Facilities from Change in Short-term Debt, Net. The correction to present borrowings and repayments on our lines of credit on a gross basis was not material to our financial statements and had no impact on our previously reported net income, changes in shareholders' equity, financial position or net cash flows from financing activities.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEMS

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of final pronouncements that impact our financial statements.

Pronouncement Adopted During 2009

The following standard was effective during 2009. Consequently, the financial statements reflect its impact.

SFAS 160 "Noncontrolling Interests in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

We adopted SFAS 160 effective January 1, 2009 and retrospectively applied the presentation and disclosure requirements to prior periods. SFAS 160 is included in the "Consolidation" accounting guidance. The retrospective application of this standard:

- Reclassifies Minority Interest Expense of $4 million and $3 million and Interest Expense of $1 million and $3 million for the years ended December 31, 2008 and 2007, respectively, as Net Income Attributable to Noncontrolling Interest below Net Income in the presentation of Earnings Attributable to AEP Common Shareholders in our Consolidated Statements of Income.
- Repositions Preferred Stock Dividend Requirements of Subsidiaries of $3 million for the years ended December 31, 2008 and 2007 below Net Income in the presentation of Earnings Attributable to AEP Common Shareholders in our Consolidated Statements of Income.

- Reclassifies minority interest of $17 million as of December 31, 2008 previously included in Deferred Credits and Other Noncurrent Liabilities and Total Liabilities as Noncontrolling Interests in Total Equity on our Consolidated Balance Sheets.
- Separately reflects changes in Noncontrolling Interests on the Consolidated Statements of Changes in Equity and Comprehensive Income (Loss).
- Reclassifies dividends paid to noncontrolling interests of $6 million for the years ended December 31, 2008 and 2007 from Operating Activities to Financing Activities in our Consolidated Statements of Cash Flows.

Pronouncements Adopted During The First Quarter of 2010

The following standards are effective during the first quarter of 2010. Consequently, their impact will be reflected in the first quarter of 2010 financial statements when filed. The following paragraphs discuss their expected impact on future financial statements.

SFAS 166 "Accounting for Transfers of Financial Assets" (SFAS 166)

In June 2009, the FASB issued SFAS 166 clarifying when a transfer of a financial asset should be recorded as a sale. The standard defines participating interest to establish specific conditions for a sale of a portion of a financial asset. This standard must be applied to all transfers after the effective date.

We prospectively adopted SFAS 166 effective January 1, 2010. AEP Credit sells an interest in receivables it acquires from certain of its affiliates to bank conduits and receives cash. As of December 31, 2009, AEP Credit had $631 million of these receivable sales outstanding. Upon adoption of SFAS 166, these transactions do not constitute a sale of receivables and will be accounted for as financings. Effective January 2010, we record the receivables and related debt on our Consolidated Balance Sheet. SFAS 166 is included in the "Transfers and Servicing" accounting guidance.

SFAS 167 "Amendments to FASB Interpretation No. 46(R)" (SFAS 167)

In June 2009, the FASB issued SFAS 167 amending the analysis an entity must perform to determine if it has a controlling interest in a variable interest entity (VIE). In addition to presentation and disclosure guidance, SFAS 167 provides that the primary beneficiary of a VIE must have both:

- The power to direct the activities of the VIE that most significantly impact the VIE's economic performance.
- The obligation to absorb the losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

We prospectively adopted SFAS 167 effective January 1, 2010. Upon adoption, we deconsolidated DHLC and began accounting for it under the equity method of accounting. SFAS 167 is included in the "Consolidation" accounting guidance.

EXTRAORDINARY ITEMS

Virginia Restructuring

In 2000, we discontinued "Regulated Operations" accounting in our Virginia jurisdiction for retail generation and supply operations due to the passage of legislation for customer choice and deregulation. In April 2007, Virginia passed legislation to reestablish regulation for retail generation and supply of electricity. As a result, we recorded an extraordinary loss of $118 million ($79 million, net of tax) in 2007 for the reestablishment of regulatory assets and liabilities related to our Virginia retail generation and supply operations.

SWEPCo Texas Restructuring

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo's SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo re-applied "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a switch to competition in the SPP area of Texas will not occur. The reapplication of "Regulated Operations" accounting guidance resulted in an $8 million ($5 million, net of tax) extraordinary loss.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2009 and 2008 by operating segment are as follows:

	Utility Operations	AEP River Operations	AEP Consolidated
		(in millions)	
Balance at December 31, 2007	$ 37	$ 39	$ 76
Impairment Losses	-	-	-
Balance at December 31, 2008	37	39	76
Impairment Losses	-	-	-
Balance at December 31, 2009	$ 37	$ 39	$ 76

In the fourth quarters of 2009 and 2008, 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. We do not have any accumulated impairment on existing goodwill.

Other Intangible Assets

Acquired intangible assets subject to amortization were $10.3 million and $12.8 million at December 31, 2009 and 2008, respectively, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2009		2008	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)		(in millions)		
Easements	10	$ 2.2	$ 1.9	$ 2.2	$ 1.6
Purchased Technology	10	10.9	8.6	10.9	7.5
Advanced Royalties	15	29.4	21.7	29.4	20.6
Total		$ 42.5	$ 32.2	$ 42.5	$ 29.7

Amortization of intangible assets was $3 million, $3 million and $4 million for 2009, 2008 and 2007, respectively. Our estimated total amortization is $2 million per year for 2010 through 2011 and $1 million per year for 2012 through 2014.

The Advanced Royalties asset class relates to the lignite mine of DHLC, a wholly-owned subsidiary of SWEPCo. In December 2008, we received an order from the LPSC that extended the useful life of the mine for an additional five years, through 2016, which is included in the amortization life and factored in the estimates noted above for future periods.

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 their state commissions. Rate matters can have a material effect on financial condition, net income and cash flows. Our recent significant rate orders and pending rate filings are addressed in this note.

CSPCo and OPCo Rate Matters

Ohio Electric Security Plan Filings

The PUCO issued an order in March 2009 that modified and approved CSPCo's and OPCo's ESPs that established rates at the start of the April 2009 billing cycle. The ESPs are in effect through 2011. The order also limits rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from these limitations. CSPCo and OPCo collected the 2009 annualized revenue increase over the last nine months of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC increase is subject to quarterly true-ups, annual accounting audits and prudence reviews. The order allows CSPCo and OPCo to defer any unrecovered FAC costs resulting from the annual caps and to accrue associated carrying charges at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC regulatory asset balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018.

Discussed below are the outstanding uncertainties related to the ESP order:

The Ohio Consumers' Counsel filed a notice of appeal with the Supreme Court of Ohio raising several issues including the alleged retroactive rates, recovery of carrying charges on certain environmental investments, Provider of Last Resort (POLR) charges and the decision not to offset rates by off-system sales margins.

The Industrial Energy Users-Ohio group filed a notice of appeal with the Supreme Court of Ohio challenging other components of the ESP order including the POLR charge, the distribution riders for gridSMART^{SM} and enhanced reliability, the PUCO's conclusion and supporting evaluation that the modified ESPs are more favorable than the expected results of a market rate offer, the unbundling of the fuel and non-fuel generation rate components, the scope and design of the fuel adjustment clause and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is still pending.

In 2009, the PUCO convened a workshop to determine the methodology for the Significantly Excessive Earnings Test (SEET). The SEET requires the PUCO to determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount would be returned to customers. The PUCO staff recommended that the SEET be calculated on an individual company basis and not on a combined CSPCo/OPCo basis and that off-system sales margins be included in the earnings test. It is unclear at this time whether the FAC phase-in deferral credits will be included in the earnings test. Management believes that CSPCo and OPCo should not be required to refund unrecovered FAC regulatory assets. The PUCO's decision on the SEET methodology is not expected to be finalized until a SEET filing is made by CSPCo and OPCo in 2010 related to 2009 earnings and the PUCO issues an order thereon. As a result, CSPCo and OPCo are unable to determine whether they will be required to return any of their ESP revenues to customers.

The following uncertainties were resolved in 2009:

Prior to the appeals discussed above, certain intervenors filed appeals of the ESP order with the Supreme Court of Ohio. One of the intervenors asked the court to stay, pending the outcome of its appeal, a portion of the authorized ESP rates which the intervenor characterized as being retroactive. The Supreme Court of Ohio denied the intervenor's request for a stay and granted motions to dismiss both appeals.

The Industrial Energy Users-Ohio group filed a complaint for writ of prohibition with the Supreme Court of Ohio requesting the Court to prohibit CSPCo and OPCo from billing and collecting any ESP rate increases because they assert that the PUCO's statutory jurisdiction over CSPCo's and OPCo's ESP application ended on December 28, 2008. CSPCo and OPCo filed a motion to dismiss the complaint for writ of prohibition. In January 2010, the Supreme Court of Ohio granted the motion to dismiss.

Management is unable to predict the outcome of the various ongoing ESP proceedings and litigation discussed above. If these proceedings result in adverse rulings, it could reduce future net income and cash flows.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. CSPCo and OPCo have each collected $12 million in pre-construction costs authorized in a June 2006 PUCO order and each incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million. The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant before June 2011, all pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. Intervenors have filed motions with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest.

CSPCo and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of regulatory cost recovery exists. Management cannot predict the outcome of the cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, the litigation will have on future net income and cash flows. However, if CSPCo and OPCo were required to refund the $24 million collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows.

Ormet

Interim Arrangement

CSPCo, OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was effective from January 2009 through September 2009. In January 2009, the PUCO approved the application. In March 2009, the PUCO approved a FAC in the ESP filings. The approval of the FAC, together with the PUCO approval of the interim arrangement, provided the basis to record regulatory assets for the difference between the approved market price and the rate paid by Ormet. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the cumulative balance of the unrecovered FAC deferrals under the interim agreement, plus a weighted average cost of capital carrying charge. As of December 31, 2009, CSPCo and OPCo had $31 million and $34 million, respectively, of recorded regulatory assets related to the interim arrangement.

In the ESP proceeding, intervenors requested that CSPCo and OPCo be required to refund these regulatory assets and requested that the PUCO prevent CSPCo and OPCo from collecting these revenues in the future. CSPCo and OPCo filed a response noting that these amounts have not been collected and, in fact, are recorded as regulatory assets with PUCO authorization, pending future authorization for recovery. The PUCO did not take any action on this request in the ESP proceeding. The intervenors raised the issue again in response to CSPCo’s and OPCo’s November 2009 filing to approve recovery of the cumulative balance of the unrecovered FAC regulatory assets under the interim agreement. If CSPCo and OPCo are not ultimately permitted to recover their under-recovery deferrals under the interim arrangement, it would reduce future net income and cash flows.

Special Arrangement

In 2009, Ormet filed an application with the PUCO for approval of a proposed 10-year power contract under which Ormet would pay varying amounts based on certain conditions, including the price of aluminum and its level of production. The difference between the amounts paid by Ormet and the otherwise applicable PUCO ESP tariff rate would be either collected from or refunded to CSPCo’s and OPCo’s retail customers. The PUCO approved the power contract through 2018 with several modifications, including maximum discounts. The PUCO authorized CSPCo and OPCo to record Economic Development Rider (EDR) regulatory assets in an amount equal to the difference between the ESP tariff rate and the rate paid by Ormet. In addition, the PUCO ordered CSPCo and OPCo to credit all Ormet-related POLR charges to reduce the EDR under-recovery regulatory asset amounts that CSPCo and OPCo would otherwise recover. The new long-term power contract became effective in September 2009, at which point CSPCo and OPCo began recording a regulatory asset for the unrecovered amounts less Ormet-related POLR revenues. In November 2009, CSPCo and OPCo appealed the POLR issue to the Supreme Court of Ohio. If the appeal is successful, it would increase the revenues collected under the EDR.

In November 2009, CSPCo and OPCo requested the PUCO to approve recovery of the 2009 under-recovery deferrals under the Ormet special arrangement and the projected 2010 deferrals as a part of the EDR. In January 2010, the PUCO approved CSPCo's and OPCo's request. As of December 31, 2009, CSPCo and OPCo had $10 million and $2 million, respectively, recorded as EDR regulatory assets under the Ormet long-term contract. Management cannot predict Ormet's on-going electric consumption levels, the price of aluminum, and/or the amounts CSPCo and OPCo will defer for future recovery through the EDR. If CSPCo and OPCo are not ultimately permitted to recover their deferrals, it would reduce future net income and cash flows.

SWEPCo Rate Matters

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in-service in 2012. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo's share estimated to cost $1.2 billion, excluding AFUDC. As of December 31, 2009, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $717 million of expenditures (including AFUDC and capitalized interest, and related transmission costs of $29 million). As of December 31, 2009, the joint owners and SWEPCo have contractual construction commitments of approximately $480 million (including related transmission costs of $3 million). SWEPCo's share of the contractual construction commitments is $351 million. If the plant is cancelled, the joint owners and SWEPCo would incur cancellation fees, based on construction status as of December 31, 2009, of approximately $136 million (including related transmission cancellation fees of $1 million). SWEPCo's share of the cancellation fees would be approximately $100 million.

Discussed below are the outstanding uncertainties related to the Turk Plant:

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN). Following an appeal by certain intervenors, the Arkansas Court of Appeals issued a unanimous decision that, if upheld by the Arkansas Supreme Court, would reverse the APSC's grant of the CECPN. The Arkansas Court of Appeals concluded that SWEPCo's need for base load capacity, the construction and financing of the Turk Plant and the proposed transmission facilities' construction and location should have been considered by the APSC in a single docket instead of separate dockets. In October 2009, the Arkansas Supreme Court granted the petitions filed by SWEPCo and the APSC to review the Arkansas Court of Appeals' decision.

The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. An intervenor filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant was unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT in all respects. SWEPCo intends to appeal the decision.

The LPSC approved SWEPCo's application to construct the Turk Plant. The Sierra Club petitioned the LPSC to begin an investigation of construction of the Turk Plant pursuant to that approval. In November 2009, the LPSC denied the Sierra Club's petition. In December 2009, the Sierra Club refiled its petition as a stand alone complaint proceeding. In February 2010, SWEPCo filed a motion to dismiss and denied the allegations in the complaint.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality (ADEQ) and commenced construction at the site. However, certain parties filed appeals of the air permit approval with the Arkansas Pollution Control and Ecology Commission (APCEC). In January 2010, the APCEC upheld the air permit. In February 2010, the parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal of the APCEC's decision with the Circuit Court of Hempstead County, Arkansas. The same parties filed a petition with the Federal EPA to review the air permit. In December 2009, the Federal EPA rejected the parties' petition on every issue except one, where the Federal EPA asked the ADEQ to supplement the air permit record on one aspect of its Best Available Control Technology analysis.

In connection with obtaining a wetlands permit, SWEPCo reported to the U.S. Army Corps of Engineers an inadvertent impact on approximately 2.5 acres of wetlands at the Turk Plant construction site prior to the receipt of the permit. SWEPCo entered into a Consent Agreement and Final Order with the Federal EPA and agreed to pay a civil penalty of approximately $29 thousand. The wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In February 2010, the Sierra Club, the Audubon Society and others filed a complaint in the Federal District Court for the Western District of Arkansas against the U.S. Army Corps of Engineers challenging the process used and the terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. SWEPCo plans to intervene in the proceeding and defend the permit.

Uncertainties that were resolved regarding the Turk Plant:

A federal court denied a request by Arkansas landowners to stop pre-construction activities and SWEPCo's motion to dismiss the subsequent appeal was granted in March 2009.

Management believes that SWEPCo's planning, certification and construction of the Turk Plant has been in material compliance with all applicable laws and regulations, except for the inadvertent wetlands intrusion discussed above. Further, management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction and place it in service or if it cannot recover all of the investment in and the expenses of the Turk Plant, it would adversely impact net income, cash flows and financial condition unless the resultant losses can be fully recovered, with a return on any unrecovered balances, through rates in all of its jurisdictions.

Stall Unit

SWEPCo is constructing the Stall Unit, an intermediate load 500 MW natural gas-fired combustion turbine combined cycle generating unit, at its existing Arsenal Hill Plant located in Shreveport, Louisiana. The Stall Unit is currently estimated to cost $437 million, including $51 million of AFUDC, and is expected to be in service in mid-2010. The LPSC and the APSC issued orders capping SWEPCo's Stall Unit construction costs at $445 million including AFUDC and excluding related transmission costs.

As of December 31, 2009, SWEPCo has capitalized construction costs of $385 million, including AFUDC, and has contractual construction commitments of an additional $22 million. If the final cost of the Stall Unit exceeds the $445 million cost cap, then the APSC or LPSC could disallow the jurisdictional allocation of construction costs in excess of the caps and thereby reduce future net income and cash flows.

Arkansas Base Rate Filing

The APSC approved a base rate increase that provides for an $18 million annual increase in revenues effective December 2009 and a decrease in annual depreciation rates of $12 million. The order also includes a separate rider of approximately $11 million annually for the recovery of carrying costs, depreciation and operation and maintenance expenses on the Stall Unit once it is placed in service as expected in mid-2010.

2009 Texas Base Rate Filing

In August 2009, SWEPCo filed a rate case with the PUCT to increase its base rates by approximately $75 million annually including a return on equity of 11.5%. The filing includes financing cost riders of $32 million related to construction of the Stall Unit and Turk Plant, a vegetation management rider of $16 million and other requested increases of $27 million. The March 2010 hearings were suspended for the parties to pursue settlement discussions.

TCC and TNC Rate Matters

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After a ruling from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. The Texas Supreme Court requested a full briefing of the proceedings which have concluded. The following represent issues where either the Texas District Court or the Texas Court of Appeals recommended the PUCT decision be modified:

- The Texas District Court judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. The Texas Court of Appeals reversed the District Court's unfavorable decision.

- The Texas District Court judge determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. This favorable decision was affirmed by the Texas Court of Appeals.

- The Texas Court of Appeals determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated REPs. This decision could be unfavorable unless the PUCT allows TCC to recover the refunds previously made to the REPs. See the "TCC Excess Earnings" section below.

Other matters related to the Texas restructuring appeals are:

- TCC's and TNC's final fuel reconciliations under the restructuring legislation were appealed by TCC and TNC and other parties to the Texas Supreme Court. In January 2010, the Texas Supreme Court declined to review the TCC fuel appeals. In February 2010, the Texas Supreme Court declined to review the TNC fuel appeals.

Management cannot predict the outcome of the pending court proceedings and the PUCT remand decisions. If TCC and/or TNC ultimately succeed in their appeals, it could have a favorable effect on future net income, cash flows and possibly financial condition. If intervenors succeed in their appeals, it could reduce future net income, cash flows and possibly financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In 2006, the PUCT reduced recovery of the amount securitized by $103 million of tax benefits and associated carrying costs related to TCC's generation assets. In 2006, TCC obtained a private letter ruling from the IRS which confirmed that such reduction was an IRS normalization violation. In order to avoid a normalization violation, the PUCT agreed to allow TCC to defer refunding the tax benefits of $103 million plus interest through the CTC refund period pending resolution of the normalization issue. If accrued, management estimates interest expense would have been approximately $13 million higher for the period July 2008 through December 2009. In 2008, the IRS issued final regulations, which supported the IRS' private letter ruling which would make the refunding of or the reduction of the amount securitized by such tax benefits a normalization violation. After the IRS issued its final regulations, at the request of the PUCT, the Texas Court of Appeals remanded the tax normalization issue to the PUCT for the consideration of additional evidence including the IRS regulations.

Management believes that the PUCT will ultimately allow TCC to retain the deferred amounts, which would have a favorable effect on future net income and cash flows. Although unexpected, if the PUCT fails to issue a favorable order and orders TCC to return the tax benefits to customers, the normalization violation could result in TCC's repayment to the IRS of Accumulated Deferred Investment Tax Credits (ADITC) on all property, including transmission and distribution property. This amount approximates $102 million as of December 31, 2009. It could also lead to a loss of TCC's right to claim accelerated tax depreciation in future tax returns. If TCC is required to repay its ADITC to the IRS and is also required to refund ADITC plus unaccrued interest to customers, it would reduce future net income and cash flows.

TCC Excess Earnings

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the REPs excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded $55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made to the REPs in lieu of reducing stranded costs in the true-up proceeding.

In 2005, TCC reflected the obligation to refund excess earnings to customers through the true-up process and recorded a regulatory asset of $55 million representing a receivable from the REPs for the refunds made to them by TCC. However, certain parties have taken positions that, if adopted, could result in TCC being required to refund excess earnings and interest through the true-up process without receiving a refund from the REPs. If this were to occur, it would reduce future net income and cash flows. Management cannot predict the outcome of the excess earnings remand.

OTHER TEXAS RATE MATTERS

Texas Base Rate Appeal

TCC filed a base rate case in 2006 seeking to increase base rates. The PUCT issued an order in 2007 which increased TCC's base rates by $20 million, eliminated a merger credit rider of $20 million and reduced depreciation rates by $7 million. The PUCT decision was appealed by TCC and various intervenors. On appeal, the Texas District Court affirmed the PUCT in most respects. The Texas District Court also ruled that the PUCT improperly denied TCC an AFUDC return on the prepaid pension asset that the PUCT ruled to be CWIP. The AFUDC return on the prepaid pension ruling has not been appealed. Various intervenors appealed the District Court's affirmation of the PUCT decision to the Texas Court of Appeals. Management is unable to predict the outcome of these proceedings. If the intervenor appeals are successful, it could reduce future net income and cash flows.

ETT 2007 Formation Appeal

ETT is a joint venture between AEP and MidAmerican Energy Holding Company Texas Transco, LLC. TCC and TNC have sold transmission assets both in service and under construction to ETT. The PUCT approved ETT's initial rates, a request for a transfer of in-service assets and CWIP and a certificate of convenience and necessity (CCN) to operate as a stand alone transmission utility in ERCOT. ETT was allowed a 9.96% return on equity. Intervenors appealed the PUCT's decision to the Travis County District Court. The court ruled that the PUCT exceeded its authority by approving ETT's application as a stand alone transmission utility without a service area under the wrong section of the statute. Management believes that ruling is incorrect. Moreover, ETT provided evidence in its application that ETT complied with what the court determined was the proper section of the statute. ETT and the PUCT filed appeals to the Texas Court of Appeals.

In a separate development, the Texas governor signed a new law that clarifies the PUCT's authority to grant CCNs to transmission only utilities such as ETT. ETT filed an application with the PUCT for a CCN under the new law for the purpose of confirming its authority to operate as a transmission only utility regardless of the outcome of the pending litigation. All parties to the litigation pending at the Texas Court of Appeals have stipulated agreement or indicated they are not opposed to ETT's request. A decision from the PUCT is expected in the first quarter of 2010.

As of December 31, 2009, ETT's investment in property, plant and equipment was $272 million, of which $133 million was under construction. Depending upon the result of ETT's CCN filing under the new law and the ultimate outcome of the appeals concerning the original CCN filing and any resulting remands, TCC and TNC may be required to reacquire assets and projects under construction previously transferred to ETT by TCC and TNC. TCC and TNC would not be required to acquire the competitive renewable-energy zones projects. If TCC and TNC are required to reacquire these assets and projects, it could impact cash flows and financial condition.

APCo and WPCo Rate Matters

2009 Virginia Base Rate Case

As a result of APCo's base rate case filing with the Virginia SCC requesting an annual increase of $154 million in its generation and distribution base rates, new rates became effective, subject to refund, in December 2009. Intervenors have filed testimony addressing various issues in the case, which management estimates could result in an annual revenue increases ranging from $63 million to $94 million. In February 2010, in response to customer concerns regarding higher electric bills, APCo, in working with service area legislators, proactively developed proposed legislation to suspend the collection of interim rates. The Governor of Virginia approved this legislation.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc. (Alstom), an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In October 2009, APCo started injecting CO_2 into the underground storage facilities. The injection of CO_2 required the recordation of an asset retirement obligation and an offsetting regulatory asset at its estimated net present value of $39 million. Through December 31, 2009, APCo incurred $72 million in capitalized project costs in addition to the asset retirement obligation of $39 million.

APCo earned a return on the Virginia portion of the capitalized project costs incurred through June 30, 2008. In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on its estimated increased Virginia jurisdictional share of its project costs including the related asset retirement obligation regulatory asset amortization and related expenses. Based on the favorable treatment related to the CO_2 capture validation facility in APCo's last Virginia base rate case, APCo is deferring its carbon capture expense as a regulatory asset for future recovery. The Virginia Attorney General has recommended in the pending Virginia base rate case that no recovery be allowed for the project. APCo plans to seek recovery of the West Virginia jurisdictional costs in its next West Virginia base rate filing which is expected to be filed in March 2010. If APCo does not receive full recovery of the cost of this project with a return and the future asset retirement obligation accretion, it could reduce future net income and cash flows.

APCo's Filings for an IGCC Plant

APCo filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to construct a 629 MW IGCC power plant in Mason County, West Virginia. APCo also requested the Virginia SCC and the WVPSC to approve a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing finance costs of the project during the construction period, as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. The WVPSC granted APCo the CPCN and approved the requested cost recovery. Various intervenors filed petitions with the WVPSC to reconsider the order. No action has been taken on the requests for rehearing.

In 2008, the Virginia SCC issued an order denying APCo's request for a surcharge rate mechanism based upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concerns that the estimated costs did not include a retrofitting of carbon capture and sequestration facilities. During 2009, based on an unfavorable order received in Virginia, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional CPCN granted in 2008 must be reconsidered if and when APCo proceeds forward with the IGCC plant.

Through December 31, 2009, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction.

APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and in West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs, which if not recoverable, would reduce future net income and cash flows.

APCo's and WPCo's 2009 Expanded Net Energy Charge (ENEC) Filing

APCo and WPCo made an annual filing with the WVPSC to increase their ENEC rates by approximately $442 million. APCo and WPCo also requested the WVPSC to allow APCo and WPCo to temporarily adopt a modified phased-in ENEC mechanism due to the distressed economy and the significance of the projected increase.

In September 2009, the WVPSC issued an order granting a $355 million increase to be phased in over four years with a first-year increase of $124 million. As of December 31, 2009, APCo's ENEC under-recovery balance was $282 million which is included in noncurrent regulatory assets. The WVPSC also approved a fixed annual carrying cost rate of 4%, effective October 2009, to be applied to the incremental deferred regulatory asset balance that will result from the ENEC phase-in plan.

The order lowered annual coal cost projections by $27 million and deferred recovery of unrecovered ENEC deferrals related to price increases on certain renegotiated coal contracts. The WVPSC indicated that it would review the prudency of these additional costs in the next ENEC proceeding. As of December 31, 2009, APCo has deferred $18 million of unrecovered coal costs on the renegotiated coal contracts which is included in APCo's $282 million ENEC regulatory asset and has recorded an additional $8 million in purchased fuel costs on the renegotiated coal contracts, which is recorded in Fuel on the Consolidated Balance Sheets. Although management believes the portion of its deferred ENEC under-recovery balance attributable to renegotiated coal contracts is probable of recovery, if the WVPSC were to disallow a portion of APCo's and WPCo's deferred ENEC costs including any costs incurred in the future related to the renegotiated coal contracts, it could reduce future net income and cash flows.

Virginia Environmental and Reliability (E&R) Costs Recovery Filing

Virginia law allowed APCo to defer incremental E&R costs as incurred, excluding the equity return on in-service E&R capital investments through December 2008. As of December 31, 2009, APCo had $76 million of deferred Virginia incremental E&R costs excluding $16 million of unrecognized equity carrying costs. In January 2010, the Virginia SCC approved the stipulation agreement to recover Virginia incremental E&R costs of $90 million, representing costs deferred during 2008 plus unrecognized equity costs for collection in 2010.

Virginia Fuel Factor Proceeding

The Virginia SCC issued an order which provides for a $130 million annual fuel revenue increase effective August 2009 to recover deferred and projected fuel costs.

Virginia Transmission Rate Adjustment Clause

The Virginia SCC approved APCo's Transmission Rate Adjustment Clause effective December 2009 which will increase annual revenue by $22 million to provide for eligible transmission service costs billed by PJM.

PSO Rate Matters

PSO Fuel and Purchased Power

The OCC filed a complaint with the FERC related to the allocation of off-system sales margins (OSS) among the AEP operating companies in accordance with a FERC-approved allocation agreement. The FERC issued an adverse ruling in 2008. As a result, PSO recorded a regulatory liability in 2008 to return reallocated OSS to customers. Effective with the March 2009 billing cycle, PSO began refunding the additional reallocated OSS to its customers.

A reallocation among AEP West companies of purchased power costs for periods prior to 2002 resulted in an under-recovery of $42 million of PSO fuel costs. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. The Oklahoma Industrial Energy Consumers (OIEC) has contended that PSO should not have collected the $42 million without specific OCC approval. As such, the OIEC contends that the OCC should require PSO to refund the $42 million it collected through its fuel clause. The OCC has heard the OIEC appeal and a decision is pending. If the OCC were to order PSO to refund all or a part of the $42 million, it would reduce future net income and cash flows.

2008 Oklahoma Base Rate Appeal

In January 2009, the OCC issued a final order approving an $81 million increase in PSO's non-fuel base revenues based on a 10.5% return on equity. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. PSO and intervenors filed appeals with the Oklahoma Supreme Court raising various issues. The Oklahoma Supreme Court assigned the case to the Court of Civil Appeals. If the intervenors' appeals are successful, it could reduce future net income and cash flows.

Oklahoma Capital Reliability Rider Filing

The OCC approved PSO's Capital Reliability Rider (CRR) filing to recover up to $30 million under the CRR on an annual basis beginning in January 2010 until PSO's next base rate order. The order approving the CRR requires PSO to file a base rate case no later than July 2010.

I&M Rate Matters

Indiana Fuel Clause Filing (Cook Plant Unit 1 Fire and Shutdown)

I&M filed applications with the IURC to increase its fuel adjustment charge by approximately $53 million for the period of April through September 2009. The filings sought increases for previously under-recovered fuel clause expenses.

As fully discussed in the "Cook Plant Unit 1 Fire and Shutdown" section of Note 6, Cook Unit 1 experienced a fire and unit shutdown in September 2008. Unit 1 was placed back into service in December 2009. The unit outage resulted in increased replacement power fuel costs which were included in the filing. The filing request did not include the cost of replacement power beginning December 12, 2008, the date when I&M began receiving accidental outage insurance proceeds, through the date that the unit was returned to service in December 2009.

I&M reached an agreement with intervenors to collect its existing prior period under-recovery regulatory asset deferral balance over twelve months instead of over six months as initially proposed. Under the agreement, the fuel factors were placed into effect, subject to refund, and a subdocket was established to consider issues relating to the Unit 1 shutdown, the use of the accidental outage insurance proceeds and I&M's fuel procurement practices. The orders also provided for the subdocket issues to be resolved subsequent to December 2009.

Management cannot predict the outcome of the pending subdocket proceeding or future fuel clause proceedings, including the treatment of the accidental outage insurance proceeds and whether any fuel clause revenues or insurance proceeds recognized will have to be refunded which could reduce future net income and cash flows.

2008 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In 2009, I&M filed its 2008 PSCR reconciliation with the MPSC. The filing also included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Cook Plant Unit 1 outage from mid-December 2008 through December 2009, the period during which I&M has recognized the benefit of accidental outage insurance proceeds. In December 2009, a settlement agreement was approved by the MPSC. According to the terms of the settlement agreement, issues concerning the Cook Plant Unit 1 outage were deferred to the 2009 PSCR reconciliation. Management is unable to predict the outcome of the 2009 PSCR reconciliation and whether it could reduce future net income and cash flows. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 6.

Indiana Base Rate Filing

The IURC approved a base rate increase that provides for an annual increase in revenues of $42 million effective March 2009, including a $19 million base rate increase and $23 million in additional tracker revenues for certain incurred costs, subject to true-up.

Michigan Base Rate Filing

In January 2010, I&M filed for a $63 million increase in annual base rates based on an 11.75% return on common equity. I&M can request interim rates, subject to refund, after six months. A final order from the MPSC is required within one year.

Kentucky Rate Matters

Kentucky Base Rate Filing

In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by $124 million annually based on an 11.75% return on common equity. New rates are expected to become effective in July 2010.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the shortfall in revenues.

In 2006, a FERC Administrative Law Judge (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 should not have been 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 any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision. Management believes that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers have been engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a refund of a portion or all of the unsettled SECA revenues. In December 2009, several parties filed a motion with the U.S. Court of Appeals to force the FERC to resolve the SECA issue.

The AEP East companies provided reserves for net refunds for SECA settlements applicable to the $220 million of SECA revenues collected. As of December 31, 2009, there were no in-process settlements.

Based on settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve is adequate to settle the contested SECA revenues. Management cannot predict the ultimate outcome of future settlement discussions or future FERC proceedings or court appeals. However, if the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it would reduce future net income and cash flows.

Allocation of Off-system Sales Margins

The OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies.

In 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that

AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. In February 2010, the FERC denied AEP's motion for rehearing.

In 2009, AEP made a compliance filing with the FERC and the AEP East companies refunded approximately $250 million to the AEP West companies. Following authorized regulatory treatment, the AEP West companies shared a portion of SIA margins with their customers during the period June 2000 to March 2006. In 2008, the AEP West companies recorded a provision for refund reflecting the sharing. SWEPCo refunded approximately $13 million to FERC wholesale customers and filed a settlement agreement with the PUCT that provides for the Texas retail jurisdiction amount to be included in the March 2009 fuel cost report submitted to the PUCT. SWEPCo also began refunding $10 million to its Arkansas retail customers through the energy or fuel recovery rider in December 2009. PSO began refunding approximately $54 million plus accrued interest to Oklahoma retail customers through the fuel adjustment clause over a 12-month period beginning with the March 2009 billing cycle.

TCC and TNC filed their Advanced Metering System (AMS) with the PUCT proposing to invest in AMS to be recovered through customer surcharges. In the filing, TCC and TNC proposed to apply a portion of the SIA recorded customer refunds including interest to reduce the AMS investment and the resultant associated customer surcharge. Customers that are not subject to the AMS surcharge will receive refunds. In December 2009, the PUCT approved an uncontested settlement agreement which authorized certain refunds and AMS surcharge reductions. In 2010, TCC and TNC refunded $13 million and $4 million, respectively, to customers that are not subject to the AMS. The remaining $21 million and $9 million provision as of December 31, 2009 for TCC and TNC, respectively, will be utilized to reduce the AMS surcharge.

Consultants for the LPSC issued an audit report of SWEPCo's Louisiana retail fuel adjustment clause. Within this report, the consultants for the LPSC recommended that SWEPCo refund the SIA, including interest, through the fuel adjustment clause. Other consultants for the LPSC recommended refunding the SIA through SWEPCo's formula rate plan. SWEPCo is working with the LPSC to determine how the FERC ordered refund will be made to its Louisiana retail customers. Management cannot predict if there will be any future state regulatory proceedings but believes the AEP West companies' provision for refund regarding related future state regulatory proceedings is adequate.

Modification of the Transmission Agreement (TA)

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. The delayed effective date was approved by the FERC when the FERC accepted the new TA for filing. Settlement discussions are in progress. Management is unable to predict the regulatory lag effect it will experience and its effect on future net income and cash flows due to timing of the implementation by various state regulators of the FERC's new approved TA.

PJM/MISO Market Flow Calculation Errors

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and date back to the start of the MISO market in 2005. PJM has provided MISO an initial analysis of amounts they believe they owe MISO. MISO is disputing PJM's methodology. The FERC is scheduling settlement discussions to resolve the claims. If the FERC approves a settlement above the amount the AEP East companies have recognized related to their portions of PJM's additional costs, it could reduce net income and cash flows.

5. EFFECTS OF REGULATION

Regulatory assets are comprised of the following items:

	December 31, 2009	December 31, 2008	Remaining Recovery Period
	(in millions)		
Current Regulatory Asset			
Under-recovered Fuel Costs – earns a return	$ 85	$ 134	1 year
Under-recovered Fuel Costs – does not earn a return	-	150	1 year
Total Current Regulatory Assets	$ 85	$ 284	
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered. Recovery method and timing to be determined in future proceedings:			
Regulatory Assets Currently Earning a Return			
Customer Choice Deferrals – CSPCo, OPCo (a)	$ 57	$ 55	
Storm Related Costs – CSPCo, OPCo, TCC (a)	49	50	
Line Extension Carrying Costs – CSPCo, OPCo (a)	43	31	
Acquisition of Monongahela Power – CSPCo (a)	10	9	
Regulatory Assets Currently Not Earning a Return			
Mountaineer Carbon Capture and Storage Project – APCo	111	29	
Transmission Rate Adjustment Clause – APCo (a)	26	-	
Storm Related Costs – KPCo (b)	24	-	
Environmental Rate Adjustment Clause – APCo (a)	25	-	
Special Rate Mechanism for Century Aluminum – APCo (a)	12	-	
Total Regulatory Assets Not Yet Being Recovered	357	174	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Fuel Adjustment Clause – CSPCo, OPCo	341	-	3 to 9 years
Unamortized Loss on Reacquired Debt	99	104	34 years
Storm Related Costs – PSO	53	62	4 years
Economic Development Rider – CSPCo, OPCo	12	-	1 year
Red Rock Generating Facility – PSO	11	11	47 years
Lawton Settlement – PSO	9	21	1 year
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	2,139	2,162	10 to 14 years
Income Taxes, Net	966	888	25 years
Expanded Net Energy Charge – APCo	282	-	4 years
Virginia Environmental and Reliability Costs Recovery – APCo	76	123	1 year
Postemployment Benefits	52	46	5 years
Restructuring Transition Costs – APCo, TCC	25	38	6 years
Cook Nuclear Plant Refueling Outage Levelization – I&M	22	25	3 years
Off-system Sales Margin Sharing – I&M	18	-	1 year
Vegetation Management – PSO	16	18	1 year
Asset Retirement Obligation – APCo, I&M	16	17	11 years
Total Regulatory Assets Being Recovered	4,137	3,515	
Other	101	94	various
Total Noncurrent Regulatory Assets	$ 4,595	$ 3,783	

(a) Authorization to establish regulatory asset received from commission or pursuant to legislation.
(b) Authorization to establish a $10 million regulatory asset received from the KPSC.

Regulatory liabilities are comprised of the following items:

	December 31, 2009	December 31, 2008	Remaining Refund Period
	(in millions)		
Current Regulatory Liability			
Over-recovered Fuel Costs – pays a return	$ 65	$ 66	1 year
Over-recovered Fuel Costs – does not pay a return	11	-	1 year
Total Current Regulatory Liability	$ 76	$ 66	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 2,048	$ 2,017	(a)
Deferred Investment Tax Credits	41	48	up to 13 years
Advanced Metering Infrastructure Surcharge – TCC, TNC	30	-	11 years
Transmission Cost Recovery Rider – CSPCo, OPCo	25	1	2 years
Excess Earnings – TNC	11	11	22 years
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability – I&M	281	208	(b)
Deferred Investment Tax Credits	239	246	up to 77 years
Unrealized Gain on Forward Commitments – APCo, I&M, KPCo, SWEPCo	74	91	5 years
Spent Nuclear Fuel Liability – I&M	41	37	(b)
Over-recovery of Transition Charges – TCC	38	20	10 years
Deferred State Income Tax Coal Credits – APCo	28	25	10 years
Over-recovery of PJM Expenses – I&M	18	-	1 year
Regulatory Liabilities Being Paid	2,874	2,704	
Other	35	85	various
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 2,909	$ 2,789	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

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.

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. Our subsidiaries purchase fuel, 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.

The following table summarizes our actual contractual commitments at December 31, 2009:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 3,087	$ 4,370	$ 2,484	$ 7,873	$ 17,814
Energy and Capacity Purchase Contracts (b)	82	144	195	1,161	1,582
Construction Contracts for Capital Assets (c)	245	456	312	-	1,013
Total	$ 3,414	$ 4,970	$ 2,991	$ 9,034	$ 20,409

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Represents contractual commitments for energy and capacity purchase contracts.
(c) Represents only capital assets that are contractual commitments. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

GUARANTEES

We record liabilities for guarantees in accordance with the accounting guidance for "Guarantees." 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 and debt service reserves. As the Parent, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At December 31, 2009, the maximum future payments for LOCs issued under the two $1.5 billion 5-year credit facilities are $91 million with maturities ranging from January 2010 to December 2010.

We have a $627 million 3-year credit agreement. As of December 31, 2009, $477 million of LOCs with maturities ranging from May 2010 to November 2010 were issued by subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds. We had a $350 million 364-day credit agreement that expired in April 2009.

Guarantees of Third-Party Obligations

SWEPCo

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 $65 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), a consolidated variable interest entity. 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. A new study is in process to include new, expanded areas of the mine. As of December 31, 2009, SWEPCo has collected approximately $43 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $19 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $22 million is recorded in Asset Retirement Obligations on our Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees

Contracts

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 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $1.1 billion. Approximately $1 billion of the maximum exposure relates to the Bank of America (BOA) litigation (see "Enron Bankruptcy" section of this note), of which the probable payment/performance risk is $441 million and is recorded in Deferred Credits and Other Noncurrent Liabilities on our Consolidated Balance Sheets as of December 31, 2009. The remaining exposure is remote. There are no material liabilities recorded for any indemnifications other than amounts recorded related to the BOA litigation.

Lease Obligations

We lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 13 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. Cases with similar allegations against CSPCo, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units.

In 2007, the U.S. District Court approved our consent decree with the Federal EPA, the United States Department of Justice, the states and the special interest groups. The consent decree resolved all issues related to various parties' claims against us in the NSR cases. We agreed to annual SO_2 and NO_x emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia and the installation of environmental retrofit projects at many of the plants. Under the consent decree, we paid a $15 million civil penalty and provided $36 million for environmental mitigation projects coordinated with the federal government and $24 million to the states for environmental mitigation. We expensed these amounts in 2007.

In October 2008, the court approved a consent decree for a settlement reached with the Sierra Club in a case involving CSPCo's share of jointly-owned units at the Stuart Station. The Stuart units, operated by DP&L, are equipped with selective catalytic reduction and FGD controls. Under the terms of the settlement, the joint-owners agreed to certain emission targets related to NO_x, SO_2 and PM. They also agreed to make energy efficiency and renewable energy commitments that are conditioned on receiving PUCO approval for recovery of costs. The joint-owners also agreed to forfeit 5,500 SO_2 allowances and provide $300 thousand to a third party organization to establish a solar water heater rebate program. Another case involving a jointly-owned Beckjord unit had a liability trial. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case. Following a second liability trial, the jury again found no liability at the jointly-owned Beckjord unit. In 2009, the defendants and the plaintiffs filed appeals. Beckjord is operated by Duke Energy Ohio, Inc.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint alleging violations of the CAA at SWEPCo's Welsh Plant. In 2008, a consent decree resolved all claims in the case and in a pending appeal of an altered permit for the Welsh Plant. The consent decree required SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity by 2010, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects by 2012 and pay a portion of plaintiffs' attorneys' fees and costs.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant. A permit alteration issued in March 2007 clarified or eliminated certain permit conditions. TCEQ denied a motion to overturn the permit alteration. The permit alteration was resolved by entry of the consent decree in the federal citizen suit action. In October 2008, TCEQ approved a settlement requiring SWEPCo to pay an administrative penalty of $49 thousand and to fund a supplemental environmental project in the amount of $49 thousand, and resolved all violations alleged by TCEQ.

The Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in the previous state permit. The NOV also alleges that the permit alteration issued by TCEQ was improper. In March 2008, SWEPCo met with the Federal EPA to discuss the alleged violations. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit. We are unable to predict the timing of any future action by the Federal EPA or the effect of such action on our net income, cash flows or financial condition.

Carbon Dioxide 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 trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO_2 emissions or that the Federal EPA could regulate CO_2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. In November 2009, we, along with the other defendants, filed for rehearing.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. We were initially dismissed from this case without prejudice, but are named as a defendant in a pending fourth amended complaint.

We believe the actions are without merit and intend to continue to defend against the claims.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of \$95 million to \$400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. We believe the action is 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 dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2009, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five sites for which alleged liability is unresolved. There are eight 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 four sites under state law including the I&M site discussed in the next paragraph. 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 net income.

In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M to take voluntary action necessary to prevent and/or mitigate public harm. In May 2008, I&M started remediation work in accordance with a plan approved by MDEQ. I&M recorded approximately $7 million and $4 million of expense during 2009 and 2008, respectively. As the remediation work is completed, I&M's cost may continue to increase. I&M cannot predict the amount of additional cost, if any.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made about our potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be 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. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites, except the I&M site discussed above.

Defective Environmental Equipment

As part of our continuing environmental investment program, we chose to retrofit wet flue gas desulfurization systems on several units utilizing the jet bubbling reactor (JBR) technology. The following plants have been scheduled for the installation of the JBR technology or are currently utilizing JBR retrofits:

Plant Name	Plant Owners	JBRs Installed/ Scheduled for Installation
Cardinal	OPCo/ Buckeye Power, Inc.	3
Conesville	CSPCo/Dayton Power and Light Company/ Duke Energy Ohio, Inc.	1
Clifty Creek	Indiana-Kentucky Electric Corporation	2
Kyger Creek	Ohio Valley Electric Corporation	2
Muskingum River (a)	OPCo	1
Big Sandy (a)	KPCo	1

(a) Contracts for the Muskingum River and Big Sandy projects have been temporarily suspended during the early development stages of the projects.

The retrofits on two of the Cardinal Plant units and the Conesville Plant unit are operational. Due to unexpected operating results, we completed an extensive review of the design and manufacture of the JBR internal components. Our review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. We initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. We intend to pursue our contractual and other legal remedies if we are unable to resolve these issues with Black & Veatch. If we are unsuccessful in obtaining reimbursement for the work required to remedy this situation, the cost of repair or replacement could have an adverse impact on construction costs, net income, cash flows and financial condition.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the 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. 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. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

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 most recent decommissioning cost study was performed in 2009. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $831 million to $1.5 billion in 2009 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amount recovered in rates was $16 million in 2009, $27 million in 2008 and $32 million in 2007. Reduced annual decommissioning cost recovery amounts reflect the units' longer estimated life and operating licenses granted by the NRC. Decommissioning costs recovered from customers are deposited in external trusts.

At December 31, 2009 and 2008, the total decommissioning trust fund balance was $1.1 billion and $959 million, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (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 net income, 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

The Federal government is responsible 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, 2009 and 2008, fees and related interest of $265 million and $264 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $306 million and $301 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

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 a weekly indemnity payment resulting from an insured 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 $37 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 $12.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provided $300 million of coverage through December 31, 2009. Effective January 1, 2010 commercially available insurance increased to $375 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 $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, we are initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $12.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made 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, net income, cash flows and financial condition could be adversely affected.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011.

I&M maintains property insurance through Nuclear Electric Insurance Limited (NEIL) with a $1 million deductible. As of December 31, 2009, we recorded $134 million in Prepayments and Other Current Assets on our Consolidated Balance Sheet representing recoverable amounts under the property insurance policy. Through December 31, 2009, I&M received partial payments of $118 million from NEIL for the cost incurred to repair the property damage.

I&M also maintained a separate accidental outage insurance policy with NEIL whereby, after a 12-week deductible period, I&M received weekly payments of $3.5 million for 52 weeks and $2.8 million for one week. In 2009, I&M recorded $185 million in revenue and reduced customer bills by approximately $78 million for the cost of replacement power during the outage period.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

OPERATIONAL CONTINGENCIES

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 certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of our protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See "Nuclear Contingencies" section of this footnote 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 an 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 net income, cash flows and financial condition.

Fort Wayne Lease

Since 1975 I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expires on February 28, 2010. I&M has been negotiating with Fort Wayne to purchase the assets at the end of the lease, but no agreement has been reached. Fort Wayne issued a technical notice of default under the lease to I&M in August 2009. I&M responded to Fort Wayne in October 2009 that it did not agree there was a default under the lease. In October 2009, I&M filed for declaratory and injunctive relief in Indiana state court. The parties agreed to submit this matter to mediation. In February 2010, the court issued a stay to continue mediation. I&M will seek recovery in rates for any amount it may pay related to this dispute. At this time, management cannot predict the outcome of this dispute or its potential impact on net income or cash flows.

TEM Litigation

We agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement (PPA). Beginning in May 2003, we tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. TEM and AEP separately filed declaratory judgment actions.

We reached a settlement with TEM to resolve all litigation regarding the PPA. TEM paid $255 million which we recorded as a pretax gain in January 2008 under Gain on Settlement of TEM Litigation on our Consolidated Statements of Income.

Enron Bankruptcy

In 2001, we purchased Houston Pipeline Company (HPL) from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 55 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, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of the 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. This dispute is being litigated in the Enron bankruptcy proceedings and in federal courts in Texas and New York.

In February 2004, 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 in the bankruptcy proceeding contesting Enron's right to reject these agreements.

In 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led the lending syndicate involving the monetization of the cushion gas to Enron and its subsidiaries. The lawsuit asserts that BOA made representations 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 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. In 2005, the Judge entered an order severing and transferring the declaratory judgment claims involving the right to use and cushion gas consent agreements to the Southern District of New York and retaining in the Southern District of Texas the four counts alleging breach of contract, fraud and negligent misrepresentation. Trial in federal court in Texas was continued pending a decision in the New York case.

In 2007, the judge in the New York action issued a decision on all claims, including those that were pending trial in Texas, granting BOA summary judgment and dismissing our claims. In August 2008, the court entered a final judgment of $346 million. We appealed and posted a bond covering the amount of the judgment entered against us.

In May 2009, the judge awarded $20 million of attorneys' fees to BOA. We appealed this award and posted bond covering that amount. In September 2009, the United States Court of Appeals for the Second Circuit heard oral argument on our appeal.

The liability for the BOA litigation was $441 million and $433 million including interest at December 31, 2009 and 2008, respectively. These liabilities are included in Deferred Credits and Other Noncurrent Liabilities on our Consolidated Balance Sheets.

Shareholder Lawsuits

In 2002 and 2003, three putative class action lawsuits were filed in Federal District Court, Columbus, Ohio against AEP, certain executives and AEP's 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 plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. Two of the three actions were dropped voluntarily by the plaintiffs in those cases. In 2008, the trial court denied the plaintiff's motion for class certification and ordered briefing on whether the plaintiff may maintain an ERISA claim on behalf of the Plan in the absence of class certification. In February 2010, the plaintiff settled his individual claim and the parties agreed to the dismissal of this last remaining case.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, 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 also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. These cases are at various pre-trial stages. In 2008, we settled all of the cases pending against us in California. The settlements did not impact 2008 earnings due to provisions made in prior periods. We will continue to defend each remaining case where an AEP company is a defendant. We believe the provision we have for the remaining cases is adequate.

Rail Transportation Litigation

In October 2008, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as co-owners of Oklaunion Plant, filed a lawsuit against AEP alleging breach of contract and breach of fiduciary duties related to negotiations for rail transportation services for the plant. In November 2009, all parties agreed to a settlement during court-ordered mediation.

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 because the market for power was allegedly dysfunctional at the time such contracts were executed. In September 2009, the parties reached a settlement. The settlement payment was made in February 2010.

7. ACQUISITIONS, DISPOSITIONS AND DISCONTINUED OPERATIONS

ACQUISITIONS

2009

Oxbow Lignite Company and Red River Mining Company (Utility Operations segment)

On December 29, 2009, SWEPCo purchased 50% of the Oxbow Lignite Company, LLC (OLC) membership interest for $13 million. Cleco Power LLC (Cleco) acquired the remaining 50% membership interest in the OLC for $13 million. The Oxbow Mine is located near Coushatta, Louisiana and will be used as one of the fuel sources for

SWEPCo's and Cleco's jointly-owned Dolet Hills Generating Station. SWEPCo will account for OLC as an equity investment. Also, on December 29, 2009, DHLC purchased mining equipment and assets for $16 million from the Red River Mining Company.

Valley Electric Membership Corporation (Utility Operations segment)

In November 2009, SWEPCo signed a letter of intent to purchase the transmission and distribution assets and to assume certain liabilities of Valley Electric Membership Corporation (VEMCO) for approximately $96 million. Consummation of the transaction is subject to regulatory approval by the LPSC, the APSC, the Rural Utilities Service and the National Rural Utilities Cooperative Finance Corporation. In January 2010, the VEMCO members approved the transaction. VEMCO services approximately 30,000 member customers in eight parishes south of Shreveport, Louisiana. SWEPCo expects to complete the transaction in the second quarter of 2010.

2008

Erlbacher companies (AEP River Operations segment)

In June 2008, AEP River Operations purchased certain barging assets from Missouri Barge Line Company, Missouri Dry Dock and Repair Company and Cape Girardeau Fleeting, Inc. (collectively known as Erlbacher companies) for $35 million. These assets were incorporated into AEP River Operations' business which will diversify its customer base.

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 and the assumption of liabilities of $2 million. CSPCo completed the purchase in April 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 for $325 million and the assumption of liabilities of $3 million. AEGCo completed the purchase in May 2007. Lawrenceburg 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. AEGCo sells the power to CSPCo through a FERC-approved unit power agreement.

Dresden Plant (Utility Operations segment)

In August 2007, AEGCo agreed to purchase the partially completed Dresden Plant from Dominion Resources, Inc. for $85 million and the assumption of liabilities of $2 million. AEGCo completed the purchase in September 2007. AEGCo incurred approximately $14 million, $78 million and $3 million in construction costs (excluding AFUDC) at the Dresden Plant in 2009, 2008 and 2007, respectively. During 2009, AEGCo suspended construction of the Dresden Plant as part of AEP's overall response to the economic conditions in 2009. As a result, AEGCo has stopped recording AFUDC and will resume recording AFUDC once construction is resumed in 2012. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant. When completed, the Dresden Plant will have a generating capacity of 580 MW.

DISPOSITIONS

2009

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

In 2009, TCC and TNC sold $93 million and $2 million, respectively, of transmission facilities to ETT. TCC sold an additional $16 million of transmission facilities to ETT in January 2010. There were no gains or losses recorded on these sale transactions.

2008

None

2007

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

In December 2007, TCC contributed $70 million of transmission facilities to ETT, a newly-formed affiliated entity which will own and operate transmission facilities in ERCOT. Through a series of transactions, we then sold, at net book value, a 50% equity ownership interest in ETT to a subsidiary of MidAmerican Energy Holdings Company.

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville for $43 million plus capital adjustments. The sale did not impact net income. See "Rail Transportation Litigation" section of Note 6.

Intercontinental Exchange, Inc. (ICE) (All Other)

In November 2000, we made our initial investment in ICE. An initial public offering occurred on November 15, 2005. During 2006, we sold approximately 600,000 shares and recognized a $39 million gain ($25 million, net of tax). In March 2007, we sold 130,000 shares of ICE and recognized a $16 million gain ($10 million, net of tax). We recorded the gains in Interest and Investment Income on our Consolidated Statements of Income for the year ended December 31, 2007. Our remaining investment of approximately 138,000 shares as of December 31, 2009 and 2008 is recorded in Other Temporary Investments on our Consolidated Balance Sheets.

Texas REPs (Utility Operations segment)

As part of the purchase power 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 2007, we received the final earnings sharing payment of $20 million. The payments are reflected in Other Operations on our Consolidated Statements of Income.

Sweeny Cogeneration Plant (Generation and Marketing segment)

In October 2007, we sold our 50% equity interest in Sweeny to ConocoPhillips for approximately $80 million, including working capital and the buyer's assumption of project debt. The Sweeny Cogeneration Plant is a 480 MW cogeneration plant located within ConocoPhillips' Sweeny refinery complex southwest of Houston, Texas. We were the managing partner of the plant, which is co-owned by General Electric Company. As a result of the sale, we recognized a $47 million gain ($30 million, net of tax) in 2007, which is reflected in Gain on Disposition of Equity Investments, Net on our 2007 Consolidated Statement of Income.

In addition to the sale of our interest in Sweeny, we agreed to separately sell our purchase power contract for our share of power generated by Sweeny through 2014 for $11 million to ConocoPhillips. ConocoPhillips also agreed to assume certain related third-party power obligations. These transactions were completed in conjunction with the sale of our 50% equity interest in October 2007. As a result of this sale, we recognized an $11 million gain ($7 million, net of tax) in 2007, which is included in Other Revenues on our 2007 Consolidated Statement of Income. In 2007, we recognized a total of $58 million in gains on the Sweeny transactions ($37 million, net of tax).

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 those businesses or activities 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 2008 and 2007. Results of operations of these businesses are classified as shown in the following table:

	SEE-BOARD (a)	U.K. Generation (b)	Total
		(in millions)	
2009 Revenue	$ -	$ -	$ -
2009 Pretax Income	-	-	-
2009 Earnings, Net of Tax	-	-	-
2008 Revenue	$ -	$ 2	$ 2
2008 Pretax Income	-	2	2
2008 Earnings, Net of Tax	-	12	12
2007 Revenue	$ -	$ -	$ -
2007 Pretax Income	-	7	7
2007 Earnings, Net of Tax	4	20	24

(a) Relates to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD, a former U.K. utility subsidiary of AEP that was sold in 2002.
(b) The 2008 amounts relate primarily to favorable income tax reserve adjustments. The 2007 amounts relate to tax adjustments from the sale.

8. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1.

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. We merged our two qualified plans at December 31, 2008. A substantial majority of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide medical and life insurance benefits for retired employees.

We recognize the obligations associated with our defined benefit pension plan and OPEB plans in the balance sheets at fair value under the "Fair Value Measurements and Disclosures" accounting guidance. Additional disclosures about the plans are required by "Compensation – Retirement Benefits" accounting guidance. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. We record a regulatory asset for qualifying benefit costs of our regulated operations that for ratemaking purposes are deferred for future recovery.

Adjustment of pretax AOCI is required at the end of each year, for both underfunded and overfunded defined benefit 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 market conditions, investment returns and discount rates.

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, 2009, and their funded status as of December 31 of each year:

Projected Plan Obligations, Plan Assets, Funded Status as of December 31, 2009 and 2008

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
	2009	2008	2009	2008
Change in Projected Benefit Obligation	(in millions)			
Projected Obligation at January 1	$ 4,301	$ 4,109	$ 1,843	$ 1,773
Service Cost	104	100	42	42
Interest Cost	254	249	110	113
Actuarial Loss	290	139	32	2
Benefit Payments	(248)	(296)	(120)	(120)
Participant Contributions	-	-	25	24
Medicare Subsidy	-	-	9	9
Projected Obligation at December 31	$ 4,701	$ 4,301	$ 1,941	$ 1,843
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 3,161	$ 4,504	$ 1,018	$ 1,400
Actual Gain (Loss) on Plan Assets	482	(1,054)	235	(368)
Company Contributions	8	7	150	82
Participant Contributions	-	-	25	24
Benefit Payments	(248)	(296)	(120)	(120)
Fair Value of Plan Assets at December 31	$ 3,403	$ 3,161	$ 1,308	$ 1,018
Underfunded Status at December 31	$ (1,298)	$ (1,140)	$ (633)	$ (825)

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
	2009	2008	2009	2008
Assumptions				
Discount Rate	5.60%	6.00%	5.85%	6.10%
Rate of Compensation Increase	4.60%(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 2009, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with an average increase of 4.6%.

Benefit Amounts Recognized on the Balance Sheets as of December 31, 2009 and 2008

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
	2009	2008	2009	2008
	(in millions)			
Other Current Liabilities – Accrued Short-term Benefit Liability	$ (10)	$ (9)	$ (4)	$ (4)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(1,288)	(1,131)	(629)	(821)
Underfunded Status	$ (1,298)	$ (1,140)	$ (633)	$ (825)

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI) as of December 31, 2009, 2008 and 2007

	Pension Plans			Other Postretirement Benefit Plans		
	December 31,			December 31,		
	2009	2008	2007	2009	2008	2007
Components	(in millions)					
Net Actuarial Loss	$ 2,096	$ 2,024	$ 534	$ 546	$ 715	$ 231
Prior Service Cost	12	13	14	3	3	4
Transition Obligation	-	-	-	43	70	97
Pretax AOCI	$ 2,108	$ 2,037	$ 548	$ 592	$ 788	$ 332
Recorded as						
Regulatory Assets	$ 1,750	$ 1,660	$ 453	$ 380	$ 502	$ 204
Deferred Income Taxes	125	132	33	74	100	45
Net of Tax AOCI	233	245	62	138	186	83
Pretax AOCI	$ 2,108	$ 2,037	$ 548	$ 592	$ 788	$ 332

Components of the Change in Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the years ended December 31, 2009 and 2008 are as follows:

	Pensions Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,		Years Ended December 31,	
Components	2009	2008	2009	2008
	(in millions)			
Actuarial Loss (Gain) During the Year	$ 130	$ 1,527	$ (127)	$ 492
Amortization of Actuarial Loss	(59)	(37)	(42)	(9)
Prior Service Credit	-	(1)	-	-
Amortization of Transition Obligation	-	-	(27)	(27)
Total Pretax AOCI Change for the Year	$ 71	$ 1,489	$ (196)	$ 456

Pension and Other Postretirement Plans' Assets

The value of our pension plan's assets increased to $3.4 billion at December 31, 2009 from $3.2 billion at December 31, 2008. The qualified plan paid $240 million in benefits to plan participants during 2009 (nonqualified plans paid $8 million in benefits). The value of our OPEB plans' assets increased to $1.3 billion at December 31, 2009 from $1 billion at December 31, 2008. The OPEB plans paid $120 million in benefits to plan participants during 2009.

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2009:

Major Categories of Plan Assets	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities:						
Domestic	$ 1,219	$ -	$ -	$ -	$ 1,219	35.8%
International	320	-	-	-	320	9.4%
Real Estate Investment Trusts	87	-	-	-	87	2.6%
Common Collective Trust – International	-	161	-	-	161	4.7%
Subtotal Equities	1,626	161	-	-	1,787	52.5%
Fixed Income:						
United States Government and Agency Securities	-	233	-	-	233	6.9%
Corporate Debt	-	831	-	-	831	24.4%
Foreign Debt	-	171	-	-	171	5.0%
State and Local Government	-	35	-	-	35	1.0%
Other – Asset Backed	-	27	-	-	27	0.8%
Subtotal Fixed Income	-	1,297	-	-	1,297	38.1%
Real Estate	-	-	90	-	90	2.7%
Alternative Investments	-	-	106	-	106	3.1%
Securities Lending	-	173	-	-	173	5.1%
Securities Lending Collateral (a)	-	-	-	(196)	(196)	(5.8)%
Cash and Cash Equivalents (b)	-	116	-	4	120	3.5%
Other – Pending Transactions and Accrued Income (c)	-	-	-	26	26	0.8%
Total	$ 1,626	$ 1,747	$ 196	$ (166)	$ 3,403	100.0%

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of real estate and alternative investments classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments (in millions)	Total Level 3
Balance as of January 1, 2009	$ 137	$ 106	$ 243
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(47)	(14)	(61)
Relating to Assets Sold During the Period	-	1	1
Purchases and Sales	-	13	13
Transfers in and/or out of Level 3	-	-	-
Balance as of December 31, 2009	$ 90	$ 106	$ 196

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2009:

Major Categories of Plan Assets	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities:						
Domestic	$ 343	$ -	$ -	$ -	$ 343	26.2%
International	375	-	-	-	375	28.7%
Common Collective Trust – International	-	93	-	-	93	7.1%
Subtotal Equities	718	93	-	-	811	62.0%
Fixed Income:						
Common Collective Trust – Debt	-	38	-	-	38	2.9%
United States Government and Agency Securities	-	42	-	-	42	3.2%
Corporate Debt	-	141	-	-	141	10.8%
Foreign Debt	-	32	-	-	32	2.4%
State and Local Government	-	6	-	-	6	0.5%
Other – Asset Backed	-	2	-	-	2	0.2%
Subtotal Fixed Income	-	261	-	-	261	20.0%
Trust Owned Life Insurance:						
International Equities	-	75	-	-	75	5.7%
United States Bonds	-	131	-	-	131	10.0%
Cash and Cash Equivalents (a)	7	14	-	1	22	1.7%
Other – Pending Transactions and Accrued Income (b)	-	-	-	8	8	0.6%
Total	$ 725	$ 574	$ -	$ 9	$ 1,308	100.0%

(a) Amounts in "Other" column primarily represent foreign currency holdings.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The asset allocations for our plans at the end of 2008 by asset category, were as follows:

Asset Category	Percentage of Plan Assets at December 31, 2008	
	Pension Plans	Other Postretirement Benefit Plans
Equity Securities	47%	53%
Real Estate	6%	-
Debt Securities	42%	43%
Cash and Cash Equivalents	5%	4%
Total	100%	100%

Significant Concentrations of Risk Within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. We monitor the plan to control security diversification and ensure compliance with our investment policy. At December 31, 2009, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Determination of Pension Expense

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, 2009**	**2008**
	(in millions)	
Qualified Pension Plans	$ 4,539	$ 4,119
Nonqualified Pension Plans	90	80
Total	$ 4,629	$ 4,199

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, 2009 and 2008 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2009	**2008**
	(in millions)	
Projected Benefit Obligation	$ 4,701	$ 4,301
Accumulated Benefit Obligation	$ 4,629	$ 4,199
Fair Value of Plan Assets	3,403	3,161
Underfunded Accumulated Benefit Obligation	$ 1,226	$ 1,038

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $160 million and the OPEB plans of $117 million during 2010. The amount for the pension plans is at least the minimum amount required by ERISA plus payment of unfunded nonqualified benefits. For the qualified pension plan, we may make additional discretionary contributions to maintain the funded status of the plan. The contribution to the OPEB plans is generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of our Medicare subsidy receipts.

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 OPEB are as follows:

	Pension Plans	**Other Postretirement Benefit Plans**	
	Pension Payments	**Benefit Payments**	**Medicare Subsidy Receipts**
		(in millions)	
2010	$ 332	$ 119	$ (10)
2011	342	130	(11)
2012	348	139	(13)
2013	355	148	(14)
2014	358	158	(15)
Years 2015 to 2019, in Total	1,871	923	(95)

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the years ended December 31, 2009, 2008 and 2007:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2009	2008	2007	2009	2008	2007
	(in millions)					
Service Cost	$ 104	$ 100	$ 96	$ 42	$ 42	$ 42
Interest Cost	254	249	235	110	113	104
Expected Return on Plan Assets	(321)	(336)	(340)	(80)	(111)	(104)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost	-	1	-	-	-	-
Amortization of Net Actuarial Loss	59	37	59	42	9	12
Net Periodic Benefit Cost	96	51	50	141	80	81
Capitalized Portion	(30)	(16)	(14)	(44)	(25)	(25)
Net Periodic Benefit Cost Recognized as Expense	$ 66	$ 35	$ 36	$ 97	$ 55	$ 56

Estimated amounts expected to be amortized to net periodic benefit costs for our plans during 2010 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 99	$ 29
Prior Service Cost	1	-
Transition Obligation	-	27
Total Estimated 2010 Pretax AOCI Amortization	$ 100	$ 56
Expected to be Recorded as		
Regulatory Asset	$ 82	$ 37
Deferred Income Taxes	6	7
Net of Tax AOCI	12	12
Total	$ 100	$ 56

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2009	2008	2007	2009	2008	2007
Discount Rate	6.00%	6.00%	5.75%	6.10%	6.20%	5.85%
Expected Return on Plan Assets	8.00%	8.00%	8.50%	7.75%	8.00%	8.00%
Rate of Compensation Increase	5.90%	5.90%	5.90%	N/A	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2009 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 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2009	2008
Initial	6.50%	7.00%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2012	2012

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 20	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	217	(180)

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. We provided matching contributions of 75% of the first 6% of eligible compensation contributed by an employee in 2008. Effective January 1, 2009, we match the first 1% of eligible employee contributions at 100% and the next 5% of contributions at 70%. The cost for company matching contributions totaled $74 million in 2009, $71 million in 2008 and $66 million in 2007.

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 and benefits paid were not material in 2009, 2008 and 2007.

9. BUSINESS SEGMENTS

Our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable 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.

AEP River Operations

- Commercial barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 49% of the barging is for transportation of agricultural products, 27% for coal, 8% for steel and 16% for other commodities.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT.

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

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually settle and completely expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006.

The tables below present our reportable segment information for the years ended December 31, 2009, 2008 and 2007 and balance sheet information as of December 31, 2009 and 2008. These amounts include certain estimates and allocations where necessary.

		Nonutility Operations				
Year Ended December 31, 2009	**Utility Operations**	**AEP River Operations**	**Generation and Marketing**	**All Other (a)**	**Reconciling Adjustments**	**Consolidated**
			(in millions)			
Revenues from:						
External Customers	$ 12,733 (e)	$ 490	$ 281	$ (15)	$ -	$ 13,489
Other Operating Segments	70 (e)	18	5	36	(129)	-
Total Revenues	$ 12,803	$ 508	$ 286	$ 21	$ (129)	$ 13,489
Depreciation and Amortization	$ 1,561	$ 17	$ 29	$ 2	$ (12)(b)	$ 1,597
Interest Income	4	-	-	47	(40)	11
Interest Expense	916	5	21	86	(55)(b)	973
Income Tax Expense (Credit)	553	23	-	(1)	-	575
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 1,329	$ 47	$ 41	$ (47)	$ -	$ 1,370
Extraordinary Loss, Net of Tax	(5)	-	-	-	-	(5)
Net Income (Loss)	$ 1,324	$ 47	$ 41	$ (47)	$ -	$ 1,365
Gross Property Additions	$ 2,813	$ 81	$ 1	$ 1	$ -	$ 2,896

Year Ended December 31, 2008	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 13,326 (e)	$ 616	$ 485	$ 13	$ -	$ 14,440
Other Operating Segments	240 (e)	30	(122)	9	(157)	-
Total Revenues	$ 13,566	$ 646	$ 363	$ 22	$ (157)	$ 14,440
Depreciation and Amortization	$ 1,450	$ 14	$ 28	$ 2	$ (11)(b)	$ 1,483
Interest Income	42	-	1	78	(65)	56
Interest Expense	915	5	22	94	(79)(b)	957
Income Tax Expense	515	26	17	84	-	642
Income Before Discontinued Operations and Extraordinary Loss	$ 1,123	$ 55	$ 65	$ 133	$ -	$ 1,376
Discontinued Operations, Net of Tax	-	-	-	12	-	12
Net Income	$ 1,123	$ 55	$ 65	$ 145	$ -	$ 1,388
Gross Property Additions	$ 3,871	$ 116	$ 2	$ (29)(c)	$ -	$ 3,960

Year Ended December 31, 2007	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 12,101 (e)	$ 523	$ 708	$ 48	$ -	$ 13,380
Other Operating Segments	554 (e)	14	(406)	(13)	(149)	-
Total Revenues	$ 12,655	$ 537	$ 302	$ 35	$ (149)	$ 13,380
Depreciation and Amortization	$ 1,483	$ 11	$ 29	$ 2	$ (12)(b)	$ 1,513
Interest Income	21	-	3	81	(70)	35
Interest Expense	784	5	28	108	(87)(b)	838
Income Tax Expense (Credit)	486	35	5	(10)	-	516
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 1,040	$ 61	$ 67	$ (15)	$ -	$ 1,153
Discontinued Operations, Net of Tax	-	-	-	24	-	24
Extraordinary Loss, Net of Tax	(79)	-	-	-	-	(79)
Net Income	$ 961	$ 61	$ 67	$ 9	$ -	$ 1,098
Gross Property Additions	$ 4,050	$ 12	$ 2	$ 4 (c)	$ -	$ 4,068

December 31, 2009	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
			(in millions)			
Total Property, Plant and Equipment	$ 50,905	$ 436	$ 571	$ 10	$ (238)	$ 51,684
Accumulated Depreciation and Amortization	17,110	88	168	8	(34)	17,340
Total Property, Plant and Equipment – Net	$ 33,795	$ 348	$ 403	$ 2	$ (204)	$ 34,344
Total Assets	$ 46,930	$ 495	$ 779	$ 15,094	$ (14,950)(d)	$ 48,348
Investments in Equity Method Investees	84	4	-	-	-	88

December 31, 2008	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
			(in millions)			
Total Property, Plant and Equipment	$ 48,997	$ 371	$ 565	$ 10	$ (233)	$ 49,710
Accumulated Depreciation and Amortization	16,525	73	140	8	(23)	16,723
Total Property, Plant and Equipment – Net	$ 32,472	$ 298	$ 425	$ 2	$ (210)	$ 32,987
Total Assets	$ 43,773	$ 439	$ 737	$ 14,501	$ (14,295)(d)	$ 45,155
Investments in Equity Method Investees	22	2	-	-	-	24

(a) All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually settle and completely expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.

(b) Includes eliminations due to an intercompany capital lease which began in the first quarter of 2007.

(c) Gross Property Additions for All Other includes construction expenditures of $8 million and $4 million in 2008 and 2007, respectively, related to the acquisition of turbines by one of our nonregulated, wholly-owned subsidiaries. These turbines were refurbished and transferred to a generating facility within our Utility Operations segment in the fourth quarter of 2008. The transfer of these turbines resulted in the elimination of $37 million from All Other and the addition of $37 million to Utility Operations.

(d) 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.

(e) PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEP Energy Partners, Inc. (AEPEP) (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported third-party net purchases or sales activity for these energy marketing contracts as Revenues from External Customers for the Utility Operations segment. This is offset by the Utility Operations segment's related net sales (purchases) for these contracts with AEPEP in Revenues from Other Operating Segments of $(5) million, $122 million and $406 million for the years ended December 31, 2009, 2008 and 2007, respectively. The Generation and Marketing segment also reports these purchases or sales contracts with Utility Operations as Revenues from Other Operating Segments. These affiliated contracts between PSO and SWEPCo with AEPEP ended in December 2009.

10. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and to a lesser extent foreign currency exchange risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. We manage these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Our strategy surrounding the use of derivative instruments focuses on managing our risk exposures, future cash flows and creating value based on our open trading positions by utilizing both economic and formal hedging strategies. To accomplish our objectives, we primarily employ risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

We enter into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of December 31, 2009:

Notional Volume of Derivative Instruments
December 31, 2009

Primary Risk Exposure		Volume	Unit of Measure
		(in millions)	
Commodity:			
Power		589	MWHs
Coal		60	Tons
Natural Gas		127	MMBtus
Heating Oil and Gasoline		6	Gallons
Interest Rate	$	216	USD
Interest Rate and Foreign Currency	$	83	USD

Fair Value Hedging Strategies

At certain times, 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.

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of electricity, coal, heating oil and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial gasoline and heating oil derivative contracts in order to mitigate price risk of our future fuel purchases. We do not hedge all of our fuel price risk. For disclosure purposes, these contracts are included with other hedging activity as "Commodity." We do not hedge all variable price risk exposure related to commodities.

We enter into a variety of 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 as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when 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. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet 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, supply and demand market data and assumptions. In order to determine the relevant fair values of our derivative instruments, we also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with our estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of our risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2009 and 2008 balance sheets, we netted $12 million and $11 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $98 million and $43 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following table represents the gross fair value impact of our derivative activity on our Consolidated Balance Sheet as of December 31, 2009:

Fair Value of Derivative Instruments
December 31, 2009

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**	**Other (a) (b)**	**Total**
		(in millions)			
Current Risk Management Assets	$ 1,078	$ 13	$ -	$ (831)	$ 260
Long-term Risk Management Assets	614	-	-	(271)	343
Total Assets	1,692	13	-	(1,102)	603
Current Risk Management Liabilities	997	17	3	(897)	120
Long-term Risk Management Liabilities	442	-	2	(316)	128
Total Liabilities	1,439	17	5	(1,213)	248
Total MTM Derivative Contract Net Assets (Liabilities)	$ 253	$ (4)	$ (5)	$ 111	$ 355

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Consolidated Balance Sheet on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts represent counterparty netting of risk management and hedging contracts, associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging" and dedesignated risk management contracts.

The table below presents our activity of derivative risk management contracts for the year ended December 31, 2009:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Year Ended December 31, 2009
	(in millions)
Utility Operations Revenue	$ 144
Other Revenue	19
Regulatory Assets (a)	(1)
Regulatory Liabilities (a)	113
Total Gain on Risk Management Contracts	$ 275

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current within the balance sheet.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the Consolidated Statements of Income on an accrual basis.

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. Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge.

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 on 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. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

We record realized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged, in Interest Expense on our Consolidated Statements of Income. During 2008 and 2007, we designated interest rate derivatives as fair value hedges. During 2009, we did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows 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 Net Income. We recognize any hedge ineffectiveness in Net Income 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).

Realized gains and losses on derivative contracts for the purchase and sale of electricity, coal, heating oil and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our Consolidated Statements of Income, or in Regulatory Assets or Regulatory Liabilities on our Consolidated Balance Sheet, depending on the specific nature of the risk being hedged. During 2009, 2008 and 2007, we designated commodity derivatives as cash flow hedges.

Beginning in 2009, we executed financial heating oil and gasoline derivative contracts to hedge the price risk of our diesel fuel and gasoline purchases. We reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our Consolidated Statements of Income.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2009, 2008 and 2007, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets into Depreciation and Amortization expense on our Consolidated Statements of Income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2009, 2008 and 2007, we designated foreign currency derivatives as cash flow hedges.

During 2009, we recognized a $6 million gain in Interest Expense related to hedge ineffectiveness on interest rate derivatives designated in cash flow hedge strategies. During 2009, 2008 and 2007 hedge ineffectiveness was immaterial or nonexistent for all other hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for changes in cash flow hedges for the year ended December 31, 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges

For the Year Ended December 31, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Beginning Balance in AOCI as of January 1, 2009	$ 7	$ (29)	$ (22)
Changes in Fair Value Recognized in AOCI	(6)	11	5
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Utility Operations Revenue	(15)	-	(15)
Other Revenue	(15)	-	(15)
Purchased Electricity for Resale	29	-	29
Interest Expense	-	5	5
Regulatory Assets (a)	5	-	5
Regulatory Liabilities (a)	(7)	-	(7)
Ending Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current within the balance sheet.

During 2008 and 2007, we reclassified $7 million of gains and $15 million of losses, respectively, from AOCI to net income.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2009 were:

Impact of Cash Flow Hedges on our Consolidated Balance Sheet
December 31, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 8	$ -	$ 8
Hedging Liabilities (a)	(12)	(5)	(17)
AOCI Loss Net of Tax	(2)	(13)	(15)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(2)	(4)	(6)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheet.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2009, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions is 48 months.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody's, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating.

We use standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to our pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), we are obligated to post an amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. We believe that a downgrade below investment grade is unlikely. As of December 31, 2009, the aggregate value of such derivative contracts was $10 million and we were not required to post any cash collateral. We would have been required to post $34 million of collateral for all derivative and non-derivative contracts at December 31, 2009 if our credit ratings had declined below investment grade of which $29 million was attributable to our RTO and ISO activities.

In addition, a majority of our non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under borrowed debt in excess of $50 million. On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. As of December 31, 2009, the fair value of derivative liabilities subject to cross-default provisions totaled $567 million prior to consideration of contractual netting arrangements. This exposure has been reduced by cash collateral posted of $15 million. We believe that a non-performance event under these provisions is unlikely. If a cross-default provision would have been triggered, a settlement of up to $199 million would be required after considering our contractual netting arrangements.

11. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current 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 Long-term Debt at December 31, 2009 and 2008 are summarized in the following table:

	December 31,			
	2009		2008	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 17,498	$ 18,479	$ 15,983	$ 15,113

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell of EIS and funds held by trustees primarily for the payment of debt. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31,							
	2009				2008			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)							
Cash (a)	$ 223	$ -	$ -	$ 223	$ 243	$ -	$ -	$ 243
Debt Securities	102	-	-	102	56	-	-	56
Equity Securities	19	19	-	38	27	11	10	28
Total Other Temporary Investments	$ 344	$ 19	$ -	$ 363	$ 326	$ 11	$ 10	$ 327

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

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the years ended December 31, 2009, 2008 and 2007:

Years Ended December 31,	Proceeds From Investment Sales	Purchases of Investments	Gross Realized Gains on Investment Sales	Gross Realized Losses on Investment Sales
	(in millions)			
2009	$ 35	$ 82	$ -	$ -
2008	1,185	1,118	-	-
2007	10,517	10,309	16	-

In June 2009, we recorded $9 million ($6 million, net of tax) of other-than-temporary impairments of Other Temporary Investments for equity investments of our protected cell of EIS. At December 31, 2009, we had no Other Temporary Investments with an unrealized loss position. At December 31, 2008, the fair value of corporate equity securities with an unrealized loss position was $17 million and we had no investments in a continuous unrealized loss position for more than twelve months. At December 31, 2009, the fair value of debt securities are primarily debt based mutual funds with short and intermediate maturities and variable rate demand notes.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. The assessment of whether an investment in a debt security has suffered an other-than-temporary impairment is based on whether the investor has the intent to sell or more likely than not will be required to sell the debt security before recovery of its amortized costs. The assessment of whether an investment in an equity security has suffered an other-than-temporary impairment, among other things, is based on whether the investor has the ability and intent to hold the investment to recover its value. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. I&M records unrealized gains 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 SNF 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, 2009 and December 31, 2008:

	December 31, 2009			December 31, 2008		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
			(in millions)			
Cash	$ 14	$ -	$ -	$ 18	$ -	$ -
Debt Securities:						
United States Government	401	13	(4)	295	32	-
Corporate Debt	57	5	(2)	52	6	(4)
State and Local Government	369	8	1	426	14	1
Subtotal Debt Securities	827	26	(5)	773	52	(3)
Equity Securities	551	234	(119)	469	89	(82)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,392	$ 260	$ (124)	$ 1,260	$ 141	$ (85)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2009, 2008 and 2007:

Years Ended December 31,	Proceeds From Investment Sales	Purchases of Investments	Gross Realized Gains on Investment Sales	Gross Realized Losses on Investment Sales
		(in millions)		
2009	$ 713	$ 771	$ 28	$ 1
2008	732	804	33	7
2007	696	777	15	5

The adjusted cost of debt securities was $801 million and $721 million as of December 31, 2009 and 2008, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at December 31, 2009 was as follows:

	Fair Value of Debt Securities
	(in millions)
Within 1 year	$ 19
1 year – 5 years	254
5 years – 10 years	279
After 10 years	275
Total	$ 827

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009 and 2008. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in AEP's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 427	$ -	$ -	$ 63	$ 490
Other Temporary Investments					
Cash and Cash Equivalents (a)	198	-	-	25	223
Debt Securities (c)	57	45	-	-	102
Equity Securities (d)	38	-	-	-	38
Total Other Temporary Investments	293	45	-	25	363
Risk Management Assets					
Risk Management Contracts (e) (i)	8	1,609	72	(1,119)	570
Cash Flow Hedges (e)	1	11	-	(4)	8
Dedesignated Risk Management Contracts (f)	-	-	-	25	25
Total Risk Management Assets	9	1,620	72	(1,098)	603
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (g)	-	3	-	11	14
Debt Securities: (h)					
United States Government	-	401	-	-	401
Corporate Debt	-	57	-	-	57
State and Local Government	-	369	-	-	369
Subtotal Debt Securities	-	827	-	-	827
Equity Securities (d)	551	-	-	-	551
Total Spent Nuclear Fuel and Decommissioning Trusts	551	830	-	11	1,392
Total Assets	$ 1,280	$ 2,495	$ 72	$ (999)	$ 2,848
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (e) (i)	$ 11	$ 1,415	$ 10	$ (1,205)	$ 231
Cash Flow Hedges (e)	-	21	-	(4)	17
Total Risk Management Liabilities	$ 11	$ 1,436	$ 10	$ (1,209)	$ 248

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents					
Cash and Cash Equivalents (a)	$ 304	$ -	$ -	$ 60	$ 364
Debt Securities (b)	-	47	-	-	47
Total Cash and Cash Equivalents	304	47	-	60	411
Other Temporary Investments					
Cash and Cash Equivalents (a)	217	-	-	26	243
Debt Securities (c)	56	-	-	-	56
Equity Securities (d)	28	-	-	-	28
Total Other Temporary Investments	301	-	-	26	327
Risk Management Assets					
Risk Management Contracts (e) (j)	61	2,413	86	(2,022)	538
Cash Flow Hedges (e)	6	32	-	(4)	34
Dedesignated Risk Management Contracts (f)	-	-	-	39	39
Total Risk Management Assets	67	2,445	86	(1,987)	611
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (g)	-	6	-	12	18
Debt Securities: (h)					
United States Government	-	295	-	-	295
Corporate Debt	-	52	-	-	52
State and Local Government	-	426	-	-	426
Subtotal Debt Securities	-	773	-	-	773
Equity Securities (d)	469	-	-	-	469
Total Spent Nuclear Fuel and Decommissioning Trusts	469	779	-	12	1,260
Total Assets	$ 1,141	$ 3,271	$ 86	$ (1,889)	$ 2,609
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (e) (j)	$ 77	$ 2,213	$ 37	$ (2,054)	$ 273
Cash Flow Hedges (e)	1	34	-	(4)	31
Total Risk Management Liabilities	$ 78	$ 2,247	$ 37	$ (2,058)	$ 304

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investments in money market funds.

(b) Amount represents commercial paper investments with maturities of less than ninety days.

(c) Amounts represent debt-based mutual funds.

(d) Amounts represent publicly traded equity securities and equity-based mutual funds.

(e) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."

(f) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into Utility Operations Revenues over the remaining life of the contracts.

(g) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(h) Amounts represent corporate, municipal and treasury bonds.

(i) The December 31, 2009 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($1) million in 2010, ($1) million in periods 2011-2013 and ($1) million in periods 2014-2015; Level 2 matures $65 million in 2010, $84 million in periods 2011-2013, $22 million in periods 2014-2015 and $23 million in periods 2016-2028; Level 3 matures $17 million in 2010, $16 million in periods 2011-2013, $8 million in periods 2014-2015 and $21 million in periods 2016-2028.

(j) The December 31, 2008 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($16) million in 2009; Level 2 matures $78 million in 2009, $94 million in periods 2010-2012, $25 million in periods 2013-2014 and $3 million in periods 2015-2017; Level 3 matures $25 million in 2009, $10 million in periods 2010-2012, $7 million in periods 2013-2014 and $7 million in periods 2015-2017.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2009	**Net Risk Management Assets (Liabilities)**	**Other Temporary Investments**	**Investments in Debt Securities**
		(in millions)	
Balance as of January 1, 2009	$ 49	$ -	$ -
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(4)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	44	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (c)	(17)	-	-
Transfers in and/or out of Level 3 (d)	(25)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	15	-	-
Balance as of December 31, 2009	$ 62	$ -	$ -

Year Ended December 31, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of January 1, 2008	$ 49	$ -	$ -
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	-	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	12	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (c)	-	(118)	(17)
Transfers in and/or out of Level 3 (d)	(36)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	24	-	-
Balance as of December 31, 2008	$ 49	$ -	$ -

(a) Included in revenues on our Consolidated Statements of Income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of securities or risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.
(e) 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 liabilities/assets.

12. INCOME TAXES

The details of our consolidated income taxes before discontinued operations and extraordinary loss as reported are as follows:

	Years Ended December 31, 2009	2008	2007
		(in millions)	
Federal:			
Current	$ (575)	$ 164	$ 464
Deferred	1,171	456	35
Total Federal	596	620	499
State and Local:			
Current	(76)	(1)	1
Deferred	55	22	16
Total State and Local	(21)	21	17
International:			
Current	-	1	-
Deferred	-	-	-
Total International	-	1	-
Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss	$ 575	$ 642	$ 516

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.

	Years Ended December 31, 2009	2008	2007
	(in millions)		
Net Income	$ 1,365	$ 1,388	$ 1,098
Discontinued Operations (Net of Income Tax of $(10) million and $(18) million in 2008 and 2007, respectively)	-	(12)	(24)
Extraordinary Loss (Net of Income Tax of $3 million and $39 million in 2009 and 2007, respectively)	5	-	79
Income Before Discontinued Operations and Extraordinary Loss	1,370	1,376	1,153
Income Tax Expense Before Discontinued Operations and Extraordinary Loss	575	642	516
Pretax Income	$ 1,945	$ 2,018	$ 1,669
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 681	$ 706	$ 584
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	31	23	29
Investment Tax Credits, Net	(19)	(19)	(24)
Energy Production Credits	(15)	(20)	(18)
State Income Taxes	(14)	13	11
Removal Costs	(19)	(21)	(21)
AFUDC	(36)	(24)	(18)
Medicare Subsidy	(11)	(12)	(12)
Tax Reserve Adjustments	(6)	2	(8)
Other	(17)	(6)	(7)
Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss	$ 575	$ 642	$ 516
Effective Income Tax Rate	29.6%	31.8%	30.9%

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

	December 31, 2009	2008
	(in millions)	
Deferred Tax Assets	$ 2,493	$ 2,632
Deferred Tax Liabilities	(9,065)	(7,750)
Net Deferred Tax Liabilities	$ (6,572)	$ (5,118)
Property-Related Temporary Differences	$ (4,714)	$ (3,718)
Amounts Due from Customers for Future Federal Income Taxes	(229)	(218)
Deferred State Income Taxes	(523)	(362)
Securitized Transition Assets	(712)	(776)
Regulatory Assets	(862)	(871)
Accrued Pensions	335	284
Deferred Income Taxes on Other Comprehensive Loss	203	240
Accrued Nuclear Decommissioning	(356)	(277)
Deferred Fuel	(230)	(76)
All Other, Net	516	656
Net Deferred Tax Liabilities	$ (6,572)	$ (5,118)

We, along with our subsidiaries, file a consolidated federal income tax return. 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 tax expense. The tax benefit of the Parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

We are no longer subject to U.S. federal examination for years before 2001. We have completed the exam for the years 2001 through 2006 and have issues that we are pursuing at the appeals level. The years 2007 and 2008 are currently under examination. 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. 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 net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. However, management believes that the ultimate resolution of these audits will not materially impact net income. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2000.

We sustained federal, state and local net income tax operating losses in 2009 driven primarily by bonus depreciation, a change in tax accounting method related to units of property and other book versus tax temporary differences. As a result, we accrued current federal, state and local income tax benefits in 2009. We expect to realize the federal cash flow benefits in 2010 as there is sufficient capacity in prior periods to carry the net operating loss back. The preponderance of our state and local jurisdictions do not provide for a net operating loss carry back, however we anticipate future taxable income will be sufficient to realize the tax benefit. As such, we determined that a valuation allowance is unnecessary.

We recognize interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31,		
	2009	**2008**	**2007**
		(in millions)	
Interest Expense	$ 1	$ 10	$ 2
Interest Income	5	21	5
Reversal of Prior Period Interest Expense	5	13	17

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	December 31,	
	2009	**2008**
	(in millions)	
Accrual for Receipt of Interest	$ 30	$ 33
Accrual for Payment of Interest and Penalties	18	26

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2009	2008	2007
		(in millions)	
Balance at January 1,	$ 237	$ 222	$ 175
Increase - Tax Positions Taken During a Prior Period	56	41	75
Decrease - Tax Positions Taken During a Prior Period	(65)	(45)	(43)
Increase - Tax Positions Taken During the Current Year	16	27	20
Decrease - Tax Positions Taken During the Current Year	-	(5)	-
Increase - Settlements with Taxing Authorities	1	3	2
Decrease - Lapse of the Applicable Statute of Limitations	(8)	(6)	(7)
Balance at December 31,	$ 237	$ 237	$ 222

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $137 million. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

Under the Energy Tax Incentives Act of 2005, we filed applications with the United States Department of Energy and the IRS in 2008 for the West Virginia IGCC project and in July 2008 the IRS allocated the project $134 million in credits. In September 2008, we entered into a memorandum of understanding with the IRS concerning the requirements of claiming the credits. We have until July 2010 to meet certain minimum requirements under the agreement with the IRS or the credits will be forfeited.

Several tax bills and other legislation with tax-related sections were enacted in 2007 and 2008, including the Tax Technical Corrections Act of 2007, the Tax Increase Prevention Act of 2007, the Energy Independence and Security Act of 2007 and the Emergency Economic Stabilization Act of 2008. These tax law changes enacted in 2007 and 2008 did not materially affect our net income, cash flows or financial condition.

The Economic Stimulus Act of 2008 provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a cash flow benefit of approximately $200 million in 2008.

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on net income or financial condition. However, the bonus depreciation contributed to the 2009 federal net operating tax loss and will result in a future cash flow benefit.

State Tax Legislation

Under Ohio House Bill 66, in 2005, the Ohio companies established a regulatory liability for $57 million pending rate-making treatment in Ohio. For those companies in which state income taxes flow through for rate-making purposes, regulatory assets associated with the deferred state income tax liabilities were reduced 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 and as of December 31, 2008, the $57 million regulatory liability was fully amortized.

The Ohio legislation also imposed a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. As a result of this tax, expenses of approximately $11 million, $9 million and $6 million were recorded in 2009, 2008 and 2007, respectively, in Taxes Other Than Income Taxes.

Michigan Senate Bill 0094 (MBT Act), effective January 1, 2008, provided a comprehensive restructuring of Michigan's principal business tax. The law replaced the Michigan Single Business Tax. The MBT Act is composed of a new tax which is calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The law also includes significant credits for engaging in Michigan-based activity.

In September 2007, House Bill 5198 amended the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis differences triggered as a result of the enactment of the MBT Act. This state-only temporary difference will be deducted over a 15-year period on the MBT Act tax returns starting in 2015. We have evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect our net income, cash flows or financial condition.

In March 2008, legislation was signed providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. We have evaluated the impact of the law change and the application of the law change will not materially impact our net income, cash flows or financial condition.

13. 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:

Lease Rental Costs	Years Ended December 31, 2009	2008	2007
		(in millions)	
Net Lease Expense on Operating Leases	$ 354	$ 368	$ 364
Amortization of Capital Leases	83	97	68
Interest on Capital Leases	13	16	20
Total Lease Rental Costs	$ 450	$ 481	$ 452

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 Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our Consolidated Balance Sheets.

	December 31, 2009	2008
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 75	$ 70
Distribution	-	15
Other Property, Plant and Equipment	379	443
Construction Work in Progress	-	-
Total Property, Plant and Equipment Under Capital Leases	454	528
Accumulated Amortization	139	205
Net Property, Plant and Equipment Under Capital Leases	$ 315	$ 323
Obligations Under Capital Leases		
Noncurrent Liability	$ 244	$ 226
Liability Due Within One Year	73	99
Total Obligations Under Capital Leases	$ 317	$ 325

Future minimum lease payments consisted of the following at December 31, 2009:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2010	$ 85	$ 334
2011	77	382
2012	39	264
2013	32	237
2014	26	225
Later Years	147	1,538
Total Future Minimum Lease Payments	$ 406	$ 2,980
Less Estimated Interest Element	89	
Estimated Present Value of Future Minimum Lease Payments	$ 317	

Master Lease Agreements

We lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified us in November 2008 that they elected to terminate our Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, we will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. As a result, the unamortized value of this equipment is reflected in our future minimum lease payments for 2011 ($148 million). In December 2008 and 2009, we signed new master lease agreements that include lease terms of up to 10 years.

For equipment under the GE master lease agreements that expire in 2011, 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. Under the new master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair market value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair market value and the residual value guarantee. At December 31, 2009, the maximum potential loss for these lease agreements was approximately $19 million assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

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, 2009 are as follows:

Future Minimum Lease Payments	**AEGCo**	**I&M**
	(in millions)	
2010	$ 74	$ 74
2011	74	74
2012	74	74
2013	74	74
2014	74	74
Later Years	590	590
Total Future Minimum Lease Payments	$ 960	$ 960

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as new operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years, via the renewal options. The future minimum lease obligations are $19 million for I&M and $21 million for SWEPCo for the remaining railcars as of December 31, 2009. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20-year term of the projected fair market value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $13 million ($9 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair market value would produce a sufficient sales price to avoid any loss.

Sabine Dragline Lease

During 2009, Sabine, an entity consolidated in accordance with the accounting guidance for "Variable Interest Entities," entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair market value of the existing equipment and a sale and leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. In addition to the 2009 transactions, Sabine has one additional $53 million dragline completed in 2008 that was financed under a capital lease. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2009 and 2008 Consolidated Balance Sheets. The short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our December 31, 2009 and 2008 Consolidated Balance Sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M's Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $85 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 60 months. The future payment obligations of $29 million are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment and the short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities, respectively, on our December 31, 2009 and 2008 Consolidated Balance Sheets. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2009 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	(in millions)
2010	$ 21
2011	4
2012	4
Total Future Minimum Lease Payments	$ 29

14. FINANCING ACTIVITIES

AEP Common Stock

In April 2009, we issued 69 million shares of common stock at $24.50 per share for net proceeds of $1.64 billion, which were primarily used to repay cash drawn under our credit facilities in the second quarter of 2009.

We issued 21 thousand, 68 thousand and 2.4 million shares of common stock in connection with our stock option plan during 2009, 2008 and 2007, respectively.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2009, 2008 and 2007:

Shares of AEP Common Stock	Issued	Held in Treasury
Balance, January 1, 2007	418,174,728	21,499,992
Issued	3,751,968	-
Balance, December 31, 2007	421,926,696	21,499,992
Issued	4,394,552	-
Treasury Stock Contributed to AEP Foundation	-	(1,250,000)
Balance, December 31, 2008	426,321,248	20,249,992
Issued	72,012,017	-
Treasury Stock Acquired	-	28,866
Balance, December 31, 2009	498,333,265	20,278,858

Preferred Stock

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

	December 31, 2009			
	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	606,627	$ 61

	December 31, 2008			
	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	606,878	$ 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. If the subsidiary defaults on preferred stock dividend payments for a period of one year or longer, preferred stock holders are entitled, voting separately as one class, to elect the number of directors necessary to constitute a majority of the full board of directors of the subsidiary.

(b) As of December 31, 2009 and 2008, our subsidiaries had 14,488,294 and 14,488,045 shares of $100 par value preferred stock, respectively, 22,200,000 shares of $25 par value preferred stock and 7,822,482 and 7,822,480 shares of no par value preferred stock, respectively, that were authorized but unissued.

(c) The number of shares of preferred stock redeemed was 251 shares in 2009. There were no shares of preferred stock redeemed in 2008 and the number of shares of preferred stock redeemed was 166 shares in 2007.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate December 31, 2009	Interest Rate Ranges at December 31, 2009	2008	Outstanding at December 31, 2009	2008
				(in millions)	
Senior Unsecured Notes					
2009-2014	4.76%	0.464%-6.375%	4.3875%-6.60%	$ 3,440	$ 3,790
2015-2021	5.97%	4.90%-7.95%	4.90%-6.45%	4,838	3,223
2029-2039	6.41%	5.625%-8.13%	5.625%-7.00%	4,138	4,056
Pollution Control Bonds (a)					
2010-2014 (b)	4.76%	0.22%-7.125%	1.10%-7.125%	800	606
2017-2025	4.16%	0.23%-6.05%	0.75%-6.05%	595	595
2026-2042	3.29%	0.20%-6.30%	0.85%-13.00%	764	745
Notes Payable (c)					
2009-2026	6.50%	4.47%-8.03%	4.47%-7.49%	326	233
Securitization Bonds					
2010-2020	5.35%	4.98%-6.25%	4.98%-6.25%	1,995	2,132
Junior Subordinated Debentures					
2063	8.75%	8.75%	8.75%	315	315
Spent Nuclear Fuel Obligation (d)				265	264
Other Long-term Debt (e)					
2011-2059	1.63%	1.25%-13.718%	3.20125%-13.718%	88	88
Unamortized Discount (net)				(66)	(64)
Total Long-term Debt Outstanding				17,498	15,983
Less Portion Due Within One Year				1,741	447
Long-term Portion				$ 15,757	$ 15,536

(a) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.
(b) Certain pollution control bonds are subject to mandatory redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity and repayment purposes based on the mandatory redemption date.
(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) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 6).
(e) Other long-term debt consists of an $85 million 3-year credit agreement issued by AEGCo in 2008 to be used for working capital and other general corporate purposes, and a financing obligation under a sale and leaseback agreement.

Long-term debt outstanding at December 31, 2009 is payable as follows:

	2010	2011	2012	2013	2014	After 2014	Total
				(in millions)			
Principal Amount	$ 1,741	$ 841	$ 624	$ 1,313	$ 907	$ 12,138	$ 17,564
Unamortized Discount							(66)
Total Long-term Debt Outstanding at December 31, 2009							$ 17,498

In January 2010, TCC retired $54 million of 4.98% and $32 million of 5.56% Securitization Bonds due in 2010.

As of December 31, 2009, $54 million of our auction-rate tax-exempt long-term debt remained outstanding at a rate of 0.82% that resets every 35 days. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures.

In the third quarter of 2009, we reacquired $218 million of auction-rate debt related to JMG. In July 2009, we purchased the outstanding equity ownership of JMG for $28 million which enabled us to reacquire this debt. As of December 31, 2009, trustees held, on our behalf, $321 million of our reacquired auction-rate tax-exempt long-term debt, which includes the $218 million related to JMG.

Dividend Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

The Federal Power Act prohibits the utility subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the par value of the common stock multiplied by the number of shares outstanding. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

We have issued $315 million of Junior Subordinated Debentures. The debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068. We have the option to defer interest payments on the debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire our common stock. We do not anticipate any deferral of those interest payments in the foreseeable future.

Pursuant to the leverage restrictions in our credit agreements, as of December 31, 2009, none of our retained earnings were restricted for the purpose of the payment of dividends.

Lines of Credit and Short-term Debt

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, 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, 2009, we had credit facilities totaling $3 billion to support our commercial paper program (see "Credit Facilities" section below). The maximum amount of commercial paper outstanding during 2009 was $614 million and the weighted average interest rate of commercial paper outstanding during the year was 0.61%. Our outstanding short-term debt was as follows:

	December 31,			
	2009		2008	
Type of Debt	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
	(in millions)		**(in millions)**	
Commercial Paper – AEP	$ 119	0.26%	$ -	-
Line of Credit – Sabine Mining Company (b)	7	2.06%	7	1.54%
Lines of Credit – AEP (d)	-	-	1,969	2.28%(c)
Total	$ 126		$ 1,976	

(a) Weighted average rate.
(b) Sabine Mining Company is a consolidated variable interest entity. This line of credit does not reduce available liquidity under AEP's credit facilities.
(c) Rate based on LIBOR.
(d) Paid primarily with proceeds from the April 2009 equity issuance.

Credit Facilities

As of December 31, 2009 we have credit facilities totaling $3 billion to support our commercial paper program. The facilities are structured as two $1.5 billion credit facilities of which $750 million may be issued under each credit facility as letters of credit.

We have a $627 million 3-year credit agreement. Under the facility, we may issue letters of credit. As of December 31, 2009, $477 million of letters of credit were issued by subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds. We had a $350 million 364-day credit agreement that expired in April 2009.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with bank conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the bank conduits and receives cash. This transaction constitutes a sale of receivables in accordance with the accounting guidance effective through 2009 for "Transfers and Servicing," allowing the receivables to be removed from AEP Credit's balance sheet and our Consolidated Balance Sheets and allowing AEP Credit to repay any debt obligations to the affiliated utility subsidiaries. Also, see "SFAS 166 'Accounting for Transfers of Financial Assets' " section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010 whereby such future transactions do not constitute a sale of receivables and will be accounted for as financing. We have no ownership interest in the bank 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.

In July 2009, we renewed and increased our sale of receivables agreement with AEP Credit. The sale of receivables agreement provides a commitment of $750 million from bank conduits to purchase receivables from AEP Credit. This agreement will expire in July 2010. We intend to extend or replace the sale of receivables agreement. The previous sale of receivables agreement provided a commitment of $700 million. As of December 31, 2009, AEP Credit had $631 million of these receivable sales outstanding. 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 CSPCo, I&M, KGPCo, 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.

Comparative accounts receivable information for AEP Credit is as follows:

	Years Ended December 31,		
	2009	**2008**	**2007**
		($ in millions)	
Proceeds from Sale of Accounts Receivable	$ 7,043	$ 7,717	$ 6,970
Loss on Sale of Accounts Receivable	$ 3	$ 20	$ 33
Average Variable Discount Rate	0.57%	3.19%	5.39%

	December 31,	
	2009	**2008**
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 160	$ 118
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	158	116
Retained Interest if 20% Adverse Change in Uncollectible Accounts	156	114

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

	December 31, 2009	December 31, 2008
	(in millions)	
Customer Accounts Receivable Retained	$ 492	$ 569
Accrued Unbilled Revenues Retained	503	449
Miscellaneous Accounts Receivable Retained	92	90
Allowance for Uncollectible Accounts Retained	(37)	(42)
Total Net Balance Sheet Accounts Receivable	1,050	1,066
Customer Accounts Receivable Securitized	631	650
Total Accounts Receivable Managed	$ 1,681	$ 1,716
Net Uncollectible Accounts Written Off	$ 33	$ 37

Customer accounts receivable retained and securitized for the 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 $22 million at December 31, 2009 and 2008, respectively. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

Shown below are our reconciliations of accumulated provision for uncollectable accounts:

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in millions)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2009	$ 42	$ 32	$ (3)	$ 34	$ 37
Year Ended December 31, 2008	52	28	-	38	42
Year Ended December 31, 2007	30	46	1	25	52

(a) Recoveries on accounts previously written off and 2009 reclass to Long-term Liability.
(b) Uncollectible accounts written off.

15. 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 options, to employees. A maximum of 9,000,000 shares may be used under this plan for full value share awards, which include performance units, restricted shares and restricted stock units. The Board of Directors and shareholders last approved the LTIP in 2005. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

Stock Options

We did not grant stock options in 2009, 2008 or 2007 but we do have outstanding stock options from grants in earlier periods that vested or were exercised in these years. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding 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. We record compensation cost for stock options 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.

The total fair value of stock options vested and the total intrinsic value of options exercised are as follows:

Stock Options	Years Ended December 31, 2009	2008	2007
	(in thousands)		
Fair Value of Stock Options Vested	$ 25	$ 25	$ 1,377
Intrinsic Value of Options Exercised (a)	106	655	29,389

(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, 2009, 2008 and 2007 is as follows:

	2009 Options	2009 Weighted Average Exercise Price	2008 Options	2008 Weighted Average Exercise Price	2007 Options	2007 Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Outstanding at January 1,	1,128	$ 32.73	1,196	$ 32.69	3,670	$ 34.41
Granted	-	N/A	-	N/A	-	N/A
Exercised/Converted	(21)	27.20	(68)	31.97	(2,454)	35.24
Forfeited/Expired	(18)	36.28	-	N/A	(20)	35.08
Outstanding at December 31,	1,089	32.78	1,128	32.73	1,196	32.69
Options Exercisable at December 31,	1,089	$ 32.78	1,125	$ 32.72	1,193	$ 32.68

The following table summarizes information about AEP stock options outstanding and exercisable at December 31, 2009.

2009 Range of Exercise Prices	Number of Options Outstanding and Exercisable	Weighted Average Remaining Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
	(in thousands)	(in years)		(in thousands)
$27.06-27.95	488	3.08	$ 27.39	$ 3,608
$30.76-38.65	456	1.90	34.10	600
$44.10-49.00	145	1.38	46.74	-
Total (a)	1,089	2.36	32.78	$ 4,208

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units are equal in value to the market value of shares of AEP common stock. The number of performance units held is multiplied by the 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 measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee and can range from 0% to 200%. For the three-year performance and vesting period ending in 2009 and earlier performance periods, performance units are paid in cash or stock at the employee's election unless they are needed to satisfy a participant's stock ownership requirement. Starting with the three-year performance and vesting period ending in 2010 or later, performance units are paid in cash, unless they are needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement 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 shares of AEP common stock shares and are 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. We recorded compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension

Obligations on our Consolidated Balance Sheets, 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 HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2009, 2008 and 2007 as follows:

	Years Ended December 31,		
Performance Units	**2009**	**2008**	**2007**
Awarded Units (in thousands)	1,179	1,384	867
Weighted Average Unit Fair Value at Grant Date	$ 34.32	$ 30.11	$ 47.64
Vesting Period (years)	3	3	3

Performance Units and AEP Career Shares	**Years Ended December 31,**		
(Reinvested Dividends Portion)	**2009**	**2008**	**2007**
Awarded Units (in thousands)	224	149	109
Weighted Average Grant Date Fair Value	$ 28.82	$ 37.21	$ 45.93
Vesting Period (years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant.

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 utility industry segment of the S&P 500 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 business days of the performance period. The month subsequent to the vesting date, the HR Committee certifies the performance score.

The certified performance scores and units earned for the three-year period ended December 31, 2009, 2008 and 2007 were as follows:

	Years Ended December 31,		
	2009	**2008**	**2007**
Certified Performance Score	73.5%	120.3%	154.3%
Performance Units Earned	593,175	1,088,302	1,508,383
Performance Units Manditorily Deferred as AEP Career Shares	26,635	42,214	313,781
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	27,855	66,415	68,107
Performance Units to be Paid in Cash	538,685	979,673	1,126,495

The cash payouts for the years ended December 31, 2009, 2008 and 2007 were as follows:

	Years Ended December 31,		
	2009	**2008**	**2007**
	(in thousands)		
Cash Payouts for Performance Units	$ 30,034	$ 52,960	$ 21,460
Cash Payouts for AEP Career Share Distributions	2,184	1,236	1,348

Restricted Shares and Restricted Stock Units

The independent members of the 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, 50,000 vested on January 1, 2006 and 66,666 vested on November 30, 2009. The remaining restricted shares are subject to his continued employment, of which 66,666 shares vest on November 30, 2010 and 66,666 shares will vest on November 30, 2011. Compensation cost for restricted shares 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. AEP has not granted other restricted shares. Dividends on these restricted shares are paid in cash.

The HR Committee also grants 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. For awards granted prior to 2009, the additional RSUs granted as dividends vested on the last date associated with the underlying units. For awards granted in 2009 and later, the additional RSUs granted as dividends vested on the same date as the underlying RSUs on which the dividends were awarded. 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 from the grant date.

In 2006 and 2007, the HR Committee granted a combined 23,000 of RSUs with performance vesting conditions to certain employees who are integral to our project to design and build proposed IGCC power plants. These grants vested at various stages throughout the design and planning of the IGCC plants. In May 2009, the HR Committee cancelled the remaining outstanding IGCC RSU awards of 12,390 shares.

In 2009 and 2008, the HR Committee did not grant RSUs with performance vesting conditions.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2009, 2008 and 2007 as follows:

	Years Ended December 31,		
Restricted Stock Units	**2009**	**2008**	**2007**
Awarded Units (in thousands)	130	56	148
Weighted Average Grant Date Fair Value	$ 29.29	$ 41.69	$ 45.89

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2009, 2008 and 2007 were as follows:

	Years Ended December 31,		
Restricted Shares and Restricted Stock Units	**2009**	**2008**	**2007**
	(in thousands)		
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 6,573	$ 2,619	$ 2,711
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	5,445	2,534	3,646

(a) Intrinsic value is calculated as market price.

A summary of the status of our nonvested restricted shares and RSUs as of December 31, 2009 and changes during the year ended December 31, 2009 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested at January 1, 2009	443	$ 37.04
Granted	130	29.29
Vested	(179)	36.58
Forfeited	(28)	40.94
Nonvested at December 31, 2009	366	34.12

The total aggregate intrinsic value of nonvested restricted shares and RSUs as of December 31, 2009 was $12 million and the weighted average remaining contractual life was 1.86 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Nonemployee 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 nonemployee 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.

We recorded the compensation cost for stock units when the units are awarded and adjusted the liability 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, 2009, 2008 and 2007.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2009, 2008 and 2007 as follows:

	Years Ended December 31,		
Stock Unit Accumulation Plan for Non-Employee Directors	**2009**	**2008**	**2007**
Awarded Units (in thousands)	56	43	28
Weighted Average Grant Date Fair Value	$ 29.56	$ 37.72	$ 46.46

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, 2009, 2008 and 2007 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2009	2008		2007
		(in thousands)		
Compensation Cost for Share-based Payment Arrangements (a)	$ 31,165	$ (18,028)	(b)	$ 72,004
Actual Tax Benefit Realized	10,908	(6,310)	(b)	25,201
Total Compensation Cost Capitalized	5,956	(5,026)	(b)	18,077

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance on our Consolidated Statements of Income.
(b) In 2008, AEP's declining total shareholder return and lower stock price significantly reduced the accruals for performance units.

During the years ended December 31, 2009, 2008 and 2007, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2009, there was $81 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 fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.72 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, 2009, 2008 and 2007 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2009	2008	2007
		(in thousands)	
Cash Received from Stock Options Exercised	$ 567	$ 2,170	$ 86,527
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	35	219	10,282

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 to offset AEP's tax withholding obligation.

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

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:

2009	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	$ 13,047	$ 6,460	1.6 - 3.8%	9 - 132	$ 9,998	$ 3,479	1.9 - 3.3%	20 - 70
Transmission	8,315	2,478	1.4 - 2.7%	25 - 87	-	-	-	-
Distribution	13,549	3,421	2.4 - 3.9%	11 - 75	-	-	-	-
CWIP	2,866	(19)	N.M.	N.M.	165	6	N.M.	N.M.
Other	2,616	1,130	4.2 - 12.8%	5 - 55	1,128	385	N.M.	N.M.
Total	$ 40,393	$ 13,470			$ 11,291	$ 3,870		

2008	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	$ 11,650	$ 5,922	1.6 - 3.5%	9 - 132	$ 9,592	$ 3,634	2.6 - 5.1%	20 - 61
Transmission	7,938	2,371	1.4 - 2.7%	25 - 87	-	-	-	-
Distribution	12,816	3,191	2.4 - 3.9%	11 - 75	-	-	-	-
CWIP	2,770	(59)	N.M.	N.M.	1,203	3	N.M.	N.M.
Other	2,705	1,265	4.9 - 11.3%	5 - 55	1,036	396	N.M.	N.M.
Total	$ 37,879	$ 12,690			$ 11,831	$ 4,033		

2007	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	2.0 - 3.8%	9 - 132	2.0 - 5.1%	20 - 121
Transmission	1.3 - 3.0%	25 - 87	-	-
Distribution	3.0 - 3.9%	11 - 75	-	-
CWIP	N.M.	N.M.	N.M.	N.M.
Other	4.8 - 11.3%	5 - 55	N.M.	N.M.

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. Prior to 2008, the lignite mine of DHLC was scheduled to be shut down in May 2011. In December 2007, the LPSC unanimously voted to extend the life of the lignite mine of DHLC through 2016. In December 2008, we received the final order. The average amortization rate for coal rights and mine development costs was $0.26 per ton in 2009 and 2008 and $0.66 per ton in 2007.

For rate-regulated operations, the composite depreciation rate generally includes a component for non-asset 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.

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. 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. We do not estimate the retirement for such easements because 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.

The following is a reconciliation of the 2009 and 2008 aggregate carrying amounts of ARO:

	Carrying Amount of ARO (in millions)
ARO at December 31, 2007	$ 1,078
Accretion Expense	60
Liabilities Incurred	22
Liabilities Settled	(34)
Revisions in Cash Flow Estimates	32
ARO at December 31, 2008 (a)	1,158
Accretion Expense	73
Liabilities Incurred	47
Liabilities Settled	(24)
Revisions in Cash Flow Estimates	5
ARO at December 31, 2009 (b)	$ 1,259

(a) The current portion of our ARO, totaling $4 million, is included in Other Current Liabilities on our 2008 Consolidated Balance Sheet.
(b) The current portion of our ARO, totaling $5 million, is included in Other Current Liabilities on our 2009 Consolidated Balance Sheet.

As of December 31, 2009 and 2008, our ARO liability was $1.3 billion and $1.2 billion, respectively, and included $878 million and $891 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2009 and 2008, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.1 billion and $1 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets.

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

Our amounts of allowance for borrowed, including interest capitalized, and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2009	2008	2007
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 82	$ 45	$ 33
Allowance for Borrowed Funds Used During Construction	67	75	79

Jointly-owned Electric Facilities

We have electric facilities 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, 2009		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress (i)	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5%	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5%	301	4	45
J.M. Stuart Generating Station (c)	Coal	26.0%	499	15	153
Wm. H. Zimmer Generating Station (a)	Coal	25.4%	767	4	355
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2%	255	4	188
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0%	116	5	61
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9%	497	8	350
Oklaunion Generating Station (Unit No. 1) (e)	Coal	70.3%	390	6	195
Turk Generating Plant (h)	Coal	73.33%	-	688	-
Transmission	N/A	(d)	70	1	47

			Company's Share at December 31, 2008		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress (j)	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5%	$ 18	$ 2	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5%	86	173	51
J.M. Stuart Generating Station (c)	Coal	26.0%	478	24	144
Wm. H. Zimmer Generating Station (a)	Coal	25.4%	762	4	344
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2%	255	1	182
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0%	103	10	62
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9%	491	8	336
Oklaunion Generating Station (Unit No. 1) (e)	Coal	70.3%	383	7	192
Turk Generating Plant (h)	Coal	73.33%	-	510	-
Transmission	N/A	(d)	70	-	46

(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) Varying percentages of ownership.
(e) Operated by PSO and also jointly-owned (54.7%) by TNC.
(f) Operated by Cleco Corporation, a nonaffiliated company.
(g) Operated by SWEPCo.
(h) Turk Generating Plant is currently under construction with a projected commercial operation date of 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2009, construction costs totaling $206.3 million have been billed to the other owners.
(i) Primarily relates to construction of Turk Generating Plant.
(j) Primarily relates to construction of Turk Generating Plant and environmental upgrades including the installation of flue gas desulfurization projects at Conesville Generating Station and J.M. Stuart Generating Station.

N/A = Not Applicable

17. 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 net income 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:

	2009 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions – except per share amounts)			
Revenues	$ 3,458	$ 3,202	$ 3,547	$ 3,282
Operating Income	750	682	858	481
Income Before Discontinued Operations and Extraordinary Loss	363	322	446	239
Extraordinary Loss, Net of Tax	-	(5)(a)	-	-
Net Income	363	317	446	239
Amounts Attributable to AEP Common Shareholders:				
Income Before Discontinued Operations and Extraordinary Loss	360	321	443	238
Extraordinary Loss, Net of Tax	-	(5)(a)	-	-
Net Income	360	316	443	238
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Discontinued Operations and Extraordinary Loss (b)	0.89	0.68	0.93	0.49
Extraordinary Loss per Share	-	(0.01)	-	-
Earnings per Share (b)	0.89	0.67	0.93	0.49
Diluted Earnings (Loss) per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Discontinued Operations and Extraordinary Loss (b)	0.89	0.68	0.93	0.49
Extraordinary Loss per Share	-	(0.01)	-	-
Earnings per Share (b)	0.89	0.67	0.93	0.49

	2008 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions – except per share amounts)			
Revenues	$ 3,467	$ 3,546	$ 4,191	$ 3,236 (e)
Operating Income	1,043 (c)(d)	586	737	421 (e)
Income Before Discontinued Operations and Extraordinary Loss	576 (c)(d)	281	376	143 (e)
Discontinued Operations, Net of Tax	-	1	-	11
Net Income	576 (c)(d)	282	376	154 (e)
Amounts Attributable to AEP Common Shareholders:				
Income Before Discontinued Operations and Extraordinary Loss	573 (c)(d)	280	374	141 (e)
Discontinued Operations, Net of Tax	-	1	-	11
Net Income	573 (c)(d)	281	374	152 (e)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Discontinued Operations and Extraordinary Loss (b)	1.43	0.70	0.93	0.34
Discontinued Operations per Share	-	-	-	0.03
Earnings per Share (b)	1.43	0.70	0.93	0.37
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Discontinued Operations and Extraordinary Loss (b)	1.43	0.70	0.93	0.34
Discontinued Operations per Share	-	-	-	0.03
Earnings per Share (b)	1.43	0.70	0.93	0.37

(a) See "SWEPCo Texas Restructuring" in "Extraordinary Items" section of Note 2 for discussion of the extraordinary loss recorded in the second quarter of 2009.
(b) Quarterly Earnings Per Share amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.
(c) See "TEM Litigation" section of Note 6 for discussion of the settlement reached with TEM in January 2008.
(d) Includes the favorable effect of the first quarter 2008 deferral of Oklahoma ice storm expenses incurred in January and December 2007.
(e) See "Allocation of Off-system Sales Margins" section of Note 4 for discussion of the financial statement impact of the FERC's November 2008 order related to the SIA.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing – The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page – Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com.

Inquiries Regarding Your Stock Holdings – Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
TelephoneResponseGroup:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders – (Stock held in a bank or brokerage account) – When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan – A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent.

Financial Community Inquiries – Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, bjrozsa@AEP.com; Julie Sherwood, 614-716-2663, jasherwood@ AEP.com; or Jana Croom, 614-716-3175, jtcroom@AEP.com. Individual shareholders should contact Kathleen Kozero, 614- 716-2819, klkozero@AEP.com.

Number of Shareholders – As of December 31, 2009, there were approximately 96,000 registered shareholders and approximately 271,000 shareholders holding stock in street name through a bank or broker. There were 478,054,407 shares outstanding at December 31, 2009.

Form 10-K – Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2009. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at klkozero@AEP.com.

Executive Leadership Team

Name	Age	
Michael G. Morris	63	Chairman of the Board, President and Chief Executive Officer
Nicholas K. Akins	49	Executive Vice President-Generation
Carl L. English	63	Chief Operating Officer
John B. Keane	63	Executive Vice President, General Counsel and Secretary
Venita McCellon-Allen	50	Executive Vice President-AEP Utilities East
Charles R. Patton	50	Executive Vice President-AEP Utilities West
Robert P. Powers	56	President-AEP Utilities
Brian X. Tierney	42	Executive Vice President and Chief Financial Officer
Susan Tomasky	56	President – AEP Transmission