UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **September 30, 2008**
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

Commission File Number	Registrant, State of Incorporation, Address of Principal Executive Offices, and Telephone Number	I.R.S. Employer Identification No.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
All Registrants	1 Riverside Plaza, Columbus, Ohio 43215-2373 Telephone (614) 716-1000	

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

Yes _X_ *No* ___

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated filer _X_ *Accelerated filer* ___

Non-accelerated filer ____ *Smaller reporting company* ___

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers or smaller reporting companies. See the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated filer ____ *Accelerated filer* ___

Non-accelerated filer _X_ *Smaller reporting company* ___

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).

Yes ___ *No* _X_

Columbus Southern Power Company and Indiana Michigan Power Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

	Number of shares of common stock outstanding of the registrants at October 30, 2008
American Electric Power Company, Inc.	403,554,634 ($6.50 par value)
Appalachian Power Company	13,499,500 (no par value)
Columbus Southern Power Company	16,410,426 (no par value)
Indiana Michigan Power Company	1,400,000 (no par value)
Ohio Power Company	27,952,473 (no par value)
Public Service Company of Oklahoma	9,013,000 ($15 par value)
Southwestern Electric Power Company	7,536,640 ($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
September 30, 2008

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an 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.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
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 West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
E&R	Environmental compliance and transmission and distribution system reliability.
EaR	Earnings at Risk, a method to quantify risk exposure.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EPS	Earnings Per Share.
ERCOT	Electric Reliability Council of Texas.
ETT	Electric Transmission Texas, LLC, a 50% equity interest joint venture with MidAmerican Energy Holding Company formed to own and operate electric transmission facilities in ERCOT.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46R	FIN 46R, "Consolidation of Variable Interest Entities."
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
FSP	FASB Staff Position.

Term	Meaning
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.
HPL	Houston Pipeline Company, a former AEP subsidiary.
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.
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.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System'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.
OTC	Over-the-counter.
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.
RSP	Rate Stabilization Plan.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SCR	Selective Catalytic Reduction.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.

Term	Meaning
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
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. AEP's 50% interest in Sweeny was sold in October 2007.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
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.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity (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.
- 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 disputes arising from the bankruptcy of Enron Corp. and related matters).
- Our ability to constrain operation and maintenance costs.
- The economic climate and growth or contraction, in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to refinance existing debt at attractive rates.
- 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 markets.
- 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 the recently-passed utility law in Ohio and the allocation of costs within RTOs.
- 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 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.

The registrants expressly disclaim any obligation to update any forward-looking information.

EXECUTIVE OVERVIEW

Base Rate Filings

Our significant base rate filings include:

Operating Company	Jurisdiction	Revised Annual Rate Increase Request	Projected Effective Date of Rate Increase
		(in millions)	
APCo	Virginia	$ 208	October 2008(a)
PSO	Oklahoma	117(b)	February 2009
I&M	Indiana	80	June 2009

(a) Subject to refund. An October settlement agreement of $168 million is pending with the Virginia SCC.
(b) Net of estimated amounts that PSO expects to recover through a generation cost recovery rider which will terminate upon implementation of the new base rates.

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amends the restructuring law effective July 31, 2008 and requires electric utilities to adjust their rates by filing an Electric Security Plan (ESP). In July 2008, within the parameters of the ESPs, CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year.

Credit Markets

In recent months, the world and U.S. economies have experienced significant slowdowns. These economic slowdowns have impacted and will continue to impact our residential, commercial and industrial sales. Concurrently, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting our access to capital, our liquidity, asset valuations in our trust funds, the creditworthy status of our customers, suppliers and trading partners and our cost of capital. Our financial staff actively manages these factors with oversight from our risk committee. The uncertainties in the credit markets could have significant implications on our subsidiaries since they rely on continuing access to capital to fund operations and capital expenditures.

The current credit markets are constraining our ability to issue new debt, including commercial paper, and refinance existing debt. Approximately $120 million and $300 million of our $16 billion of long-term debt as of September 30, 2008 will mature in the remainder of 2008 and 2009, respectively. We intend to refinance these maturities. To support our operations, we have $3.9 billion in aggregate credit facility commitments. These commitments include 27 different banks with no bank having more than 10% of our total bank commitments. In September 2008 and October 2008, we borrowed $600 million and $1.4 billion, respectively, under our credit agreements to enhance our cash position during this period of market disruptions. In October 2008, we also renewed our $600 million sale of receivables agreement through October 2009. At September 30, 2008, our available liquidity was approximately $3 billion.

We cannot predict the length of time the current credit situation will continue or the impact on our future operations and our ability to issue debt at reasonable interest rates. However, when market conditions improve, we plan to repay the amounts drawn under the credit facilities, re-enter the commercial paper market and issue other long-term debt. If there is not an improvement in access to capital, we believe that we have adequate liquidity to support our planned business operations and construction program through 2009.

We have significant investments in several trust funds to provide for future payments of pensions, OPEB, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are well-diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts has declined due to the decreases in the equity and fixed income markets. Although the asset values are currently lower, this has not affected the funds' ability to make their required payments. As of September 30, 2008, the decline in pension asset values will not require us to make a contribution in 2008 or 2009.

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. Our risk management organization monitors these exposures on a daily basis to limit our economic and financial statement impact on a counterparty basis. At September 30, 2008, our credit exposure net of collateral was approximately $827 million of which approximately 84% is to investment grade counterparties. At September 30, 2008, our exposure to financial institutions was $145 million, which represents 18% of our total credit exposure net of collateral (all investment grade).

Capital Expenditures

Due to recent credit market instability, we are currently reviewing our projections for capital expenditures from our previous projection of $6.75 billion for 2009 through 2010. We plan to identify reductions of approximately $750 million for 2009. We are evaluating possible additional capital reductions for 2010. We are also reviewing our projections for operation and maintenance expense. Our intent is to keep operation and maintenance expense flat in 2009 as compared to 2008.

Cook Plant Unit 1 Fire and Shutdown

Cook Plant Unit 1 (Unit 1) is a 1,030 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations likely caused by blade failure which resulted in a fire on the electric generator. This equipment is in the turbine building and is separate and isolated from the nuclear reactor. The steam turbines that caused the vibration were installed in 2006 and are under warranty from the vendor. The warranty provides for the replacement of the turbines if the damage was caused by a defect in the design or assembly of the turbines. I&M is also working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and turbine vendor to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. We cannot estimate the ultimate costs of the outage at this time. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Our preliminary analysis indicates that Unit 1 could resume operations as early as late first quarter/early second quarter of 2009 or as late as the second half of 2009, depending upon whether the damaged components can be repaired or whether they need to be replaced.

I&M maintains property insurance through NEIL with a $1 million deductible. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12 week deductible period, I&M is entitled to weekly payments of $3.5 million during the outage period for a covered loss. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

Hurricanes

During the third quarter of 2008, our CSPCo, OPCo, SWEPCo and TCC service territories were significantly impacted by Hurricanes Dolly, Gustav and/or Ike. Through September 30, 2008, we had incurred $54 million in total incremental operation and maintenance costs related to the three hurricanes. Since we believe that cost recovery related to the hurricanes is probable for most of these costs in our CSPCo, OPCo, and TCC service territories, we recorded $37 million in regulatory assets for these hurricane costs as of September 30, 2008. We intend to pursue the recovery of $11 million of incremental hurricane costs incurred in our SWEPCo service territory.

New Generation

In May 2006, we announced plans to build the Stall Unit, a new intermediate load, 500 MW, natural gas-fired generating unit at SWEPCo's existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo has received approvals from the Louisiana Public Service Commission (LPSC) and the Public Utility Commission of Texas (PUCT) to construct the Stall Unit and is currently waiting for approval from the Arkansas Public Service Commission (APSC). The Stall Unit is estimated to cost $378 million, excluding AFUDC, and is expected to be in-service in mid-2010.

In August 2006, we announced plans to jointly build the Turk Plant, a new base load, 600 MW, pulverized coal, ultra-supercritical generating unit in Arkansas. SWEPCo has received approvals from the APSC and the LPSC to construct the Turk Plant. In August 2008, the PUCT issued an order approving the Turk Plant subject to certain conditions, including the capping of capital costs of the Turk Plant at the $1.5 billion projected construction cost. SWEPCo is also working with the Arkansas Department of Environmental Quality for the approval of an air permit and the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. Once SWEPCo receives the air permit, they will commence construction. The Turk Plant is estimated to cost $1.5 billion, excluding AFUDC, with SWEPCo's portion estimated to cost $1.1 billion. If these permits are approved on a timely basis, the plant is expected to be in-service in 2012.

Fuel Costs

We currently estimate 2008 coal prices to increase by approximately 28% due to escalating domestic prices and increased needs, primarily in the east. We had initially expected coal costs to increase by 13% in 2008. We continue to see increases in prices due to expiring lower-priced coal and transportation contracts being replaced with higher-priced contracts. We have price risk exposure in Ohio, representing approximately 20% of our fuel costs, since we do not have an active fuel cost recovery mechanism. However, under Ohio's amended restructuring law, we have requested the PUCO to reinstate a fuel cost recovery mechanism effective January 1, 2009. Fuel cost adjustment rate clauses in our other jurisdictions will help offset future negative impacts of fuel price increases on our gross margins.

RESULTS OF OPERATIONS

Segments

Our principal operating business 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

- Barging operations that annually transport approximately 35 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and Lower Mississippi Rivers. Approximately 39% of the barging is for the transportation of agricultural products, 30% for coal, 14% for steel and 17% for other commodities. Effective July 30, 2008, AEP MEMCO LLC's name was changed to AEP River Operations LLC.

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 three and nine months ended September 30, 2008 and 2007.

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(in millions)			
Utility Operations	$ 357	$ 388	$ 1,030	$ 879
AEP River Operations	11	18	21	40
Generation and Marketing	16	3	43	17
All Other (a)	(10)	(2)	133	(1)
Income Before Discontinued Operations and Extraordinary Loss	$ 374	$ 407	$ 1,227	$ 935

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- 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 liquidate and completely expire in 2011.
- The first quarter of 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. The cash settlement of $255 million ($163 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP Consolidated

Third Quarter of 2008 Compared to Third Quarter of 2007

Income Before Discontinued Operations and Extraordinary Loss in 2008 decreased $33 million compared to 2007 primarily due to a decrease in Utility Operations segment earnings of $31 million. The decrease in Utility Operations segment earnings primarily relates to an increase in fuel and consumables expense in Ohio and a decrease in cooling degree days throughout our service territories, partially offset by increases in retail margins due to rate increases in Ohio, Virginia, West Virginia, Texas and Oklahoma.

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 403 million as of September 30, 2008.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Income Before Discontinued Operations and Extraordinary Loss in 2008 increased $292 million compared to 2007 primarily due to income of $163 million (net of tax) from the cash settlement received in 2008 related to a power purchase-and-sale agreement with TEM and an increase in Utility Operations segment earnings of $151 million. The increase in Utility Operations segment earnings primarily relates to rate increases implemented since the second quarter of 2007 in Ohio, Virginia, West Virginia, Texas and Oklahoma and higher off-system sales, partially offset by higher interest and fuel expenses.

Average basic shares outstanding increased to 402 million in 2008 from 398 million in 2007 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 403 million as of September 30, 2008.

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.

Utility Operations Income Summary
For the Three and Nine Months Ended September 30, 2008 and 2007

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(in millions)			
Revenues	$ 3,968	$ 3,600	$ 10,575	$ 9,587
Fuel and Purchased Power	1,841	1,413	4,428	3,641
Gross Margin	2,127	2,187	6,147	5,946
Depreciation and Amortization	379	374	1,099	1,122
Other Operating Expenses	1,034	1,037	3,001	2,985
Operating Income	714	776	2,047	1,839
Other Income, Net	46	27	135	72
Interest Charges and Preferred Stock Dividend Requirements	225	213	653	599
Income Tax Expense	178	202	499	433
Income Before Discontinued Operations and Extraordinary Loss	$ 357	$ 388	$ 1,030	$ 879

Summary of Selected Sales Data
For Utility Operations
For the Three and Nine Months Ended September 30, 2008 and 2007

Energy/Delivery Summary	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(in millions of KWH)			
Energy				
Retail:				
Residential	12,754	13,749	37,084	38,015
Commercial	10,794	11,164	30,249	30,750
Industrial	14,761	14,697	44,171	43,110
Miscellaneous	668	686	1,916	1,932
Total Retail	38,977	40,296	113,420	113,807
Wholesale	13,130	13,493	35,728	31,648
Delivery				
Texas Wires – Energy delivered to customers served by AEP’s Texas Wires Companies	7,961	7,721	20,916	20,297
Total KWHs	60,068	61,510	170,064	165,752

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 associated number of customers within each.

Summary of Weather Data
Summary of Heating and Cooling Degree Days for Utility Operations
For the Three and Nine Months Ended September 30, 2008 and 2007

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
	(in degree days)			
Weather Summary				
Eastern Region				
Actual – Heating (a)	-	2	1,960	2,041
Normal – Heating (b)	7	7	1,950	1,973
Actual – Cooling (c)	651	808	924	1,189
Normal – Cooling (b)	687	685	969	963
Western Region (d)				
Actual – Heating (a)	-	-	989	994
Normal – Heating (b)	2	2	967	993
Actual – Cooling (c)	1,250	1,406	1,951	2,084
Normal – Cooling (b)	1,402	1,411	2,074	2,084

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

Third Quarter of 2008 Compared to Third Quarter of 2007

Reconciliation of Third Quarter of 2007 to Third Quarter of 2008
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Third Quarter of 2007		$ 388
Changes in Gross Margin:		
Retail Margins	(81)	
Off-system Sales	(7)	
Transmission Revenues	4	
Other	24	
Total Change in Gross Margin		(60)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	-	
Depreciation and Amortization	(5)	
Taxes Other Than Income Taxes	2	
Carrying Costs Income	7	
Interest Income	8	
Other Income, Net	5	
Interest and Other Charges	(12)	
Total Change in Operating Expenses and Other		5
Income Tax Expense		24
Third Quarter of 2008		$ 357

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss decreased $31 million to $357 million in 2008. The key drivers of the decrease were a $60 million decrease in Gross Margin offset by a $5 million decrease in Operating Expenses and Other and a $24 million decrease in Income Tax Expense.

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

- Retail Margins decreased $81 million primarily due to the following:
  - A $78 million increase in fuel and consumable expenses in Ohio. CSPCo and OPCo have applied for an active fuel clause in their Ohio ESP to be effective January 1, 2009.
  - An $80 million decrease in usage primarily due to a 19% decrease in cooling degree days in our eastern region, an 11% decrease in cooling degree days in our western region as well as outages caused by Hurricanes Dolly, Gustav and Ike. Approximately 17% of our reduction in load was attributable to these storms.

  These decreases were partially offset by:
  - A $61 million increase related to net rate increases implemented in our Ohio jurisdictions, an $8 million increase related to recovery of E&R costs in Virginia and the construction financing costs rider in West Virginia, a $6 million increase in base rates in Texas and a $6 million increase in base rates in Oklahoma.
  - A $9 million increase related to increased usage by Ormet, an industrial customer in Ohio. See "Ormet" section of Note 3.
- Margins from Off-system Sales decreased $7 million primarily due to lower trading margins and the favorable effects of a fuel reconciliation recorded in our western service territory in the third quarter of 2007, partially offset by increases in East physical off-system sales margins due mostly to higher prices.
- Transmission Revenues increased $4 million primarily due to increased rates in the SPP region.
- Other revenues increased $24 million primarily due to increased third-party engineering and construction work and an increase in pole attachment revenue.

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

- Other Operation and Maintenance expenses were flat in comparison to 2007. We experienced decreases related to the following:
  - A $77 million decrease related to the recording of the NSR settlement in the third quarter of 2007. We are evaluating methods to pursue recovery in all of our affected jurisdictions.
  - A $9 million decrease related to the establishment of a regulatory asset in the third quarter of 2008 for Virginia's share of previously expended NSR settlement costs.

  These decreases were offset by:
  - A $24 million increase in non-storm system improvements, customer work and other distribution expenses.
  - A $21 million increase in storm restoration costs, primarily related to Hurricanes Dolly, Gustav and Ike.
  - A $15 million increase in recoverable PJM expenses in Ohio.
  - A $10 million increase in generation plant maintenance.
  - An $8 million increase in recoverable customer account expenses related to the Universal Service Fund for Ohio customers who qualify for payment assistance.
  - An $8 million increase in transmission expenses for tree trimming and reliability.
- Depreciation and Amortization expense increased $5 million primarily due to higher depreciable property balances from the installation of environmental upgrades.
- Carrying Costs Income increased $7 million primarily due to increased carrying cost income on cost deferrals in Virginia and Oklahoma.
- Interest Income increased $8 million primarily due to the favorable effect of claims for refund filed with the IRS.
- Interest and Other Charges increased $12 million primarily due to additional debt issued and higher interest rates on variable rate debt.
- Income Tax Expense decreased $24 million due to a decrease in pretax income.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Reconciliation of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2008
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Nine Months Ended September 30, 2007		$ 879
Changes in Gross Margin:		
Retail Margins	79	
Off-system Sales	73	
Transmission Revenues	22	
Other Revenues	27	
Total Change in Gross Margin		201
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	11	
Gain on Dispositions of Assets, Net	(18)	
Depreciation and Amortization	23	
Taxes Other Than Income Taxes	(9)	
Carrying Costs Income	26	
Interest Income	25	
Other Income, Net	12	
Interest and Other Charges	(54)	
Total Change in Operating Expenses and Other		16
Income Tax Expense		(66)
Nine Months Ended September 30, 2008		$ 1,030

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss increased $151 million to $1,030 million in 2008. The key drivers of the increase were a $201 million increase in Gross Margin and a $16 million decrease in Operating Expenses and Other offset by a $66 million increase in Income Tax Expense.

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

- Retail Margins increased $79 million primarily due to the following:
  - A $148 million increase related to net rate increases implemented in our Ohio jurisdictions, a $39 million increase related to recovery of E&R costs in Virginia and the construction financing costs rider in West Virginia, a $20 million increase in base rates in Oklahoma and a $17 million increase in base rates in Texas.
  - A $42 million increase related to increased usage by Ormet, an industrial customer in Ohio. See “Ormet” section of Note 3.
  - A $37 million net increase due to adjustments recorded in the prior year related to the 2007 Virginia base rate case which included a second quarter 2007 provision for revenue refund.
  - A $29 million increase due to coal contract amendments in 2008.

  These increases were partially offset by:
  - A $164 million increase in fuel and consumable expenses in Ohio. CSPCo and OPCo have applied for an active fuel clause in their Ohio ESP to be effective January 1, 2009.
  - A $65 million decrease in usage primarily due to a 22% decrease in cooling degree days in our eastern region and a 6% decrease in cooling degree days in our western region.
  - A $29 million increase in the sharing of off-system sales margins with customers due to an increase in total off-system sales.

- Margins from Off-system Sales increased $73 million primarily due to higher physical off-system sales in our eastern territory as the result of higher volumes and higher prices, aided by additional generation available in 2008 due to fewer planned outages and lower internal load. This increase was partially offset by lower trading margins and the favorable effects of a fuel reconciliation recorded in our western territory in the third quarter of 2007.
- Transmission Revenues increased $22 million primarily due to increased rates in the ERCOT and SPP regions.
- Other Revenues increased $27 million primarily due to increased third-party engineering and construction work, an increase in pole attachment revenue and the recording of an unfavorable provision for TCC for the refund of bonded rates recorded in 2007.

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

- Other Operation and Maintenance expenses decreased $11 million primarily due to the following:
  - A $77 million decrease related to the recording of NSR settlement costs in September 2007. We are evaluating methods to pursue recovery in all of our affected jurisdictions.
  - A $62 million decrease related to the deferral of Oklahoma storm restoration costs in the first quarter of 2008, net of amortization, as a result of a rate settlement to recover 2007 storm restoration costs.
  - A $19 million decrease in generation plant removal costs.

  These decreases were partially offset by:
  - A $33 million increase in tree trimming, reliability and system improvement expense.
  - A $29 million increase in recoverable PJM expenses in Ohio.
  - A $23 million increase in generation plant operations and maintenance expense.
  - A $21 million increase in recoverable customer account expenses related to the Universal Service Fund for Ohio customers who qualify for payment assistance.
  - A $16 million increase in storm restoration costs, primarily related to Hurricanes Dolly, Gustav and Ike, which occurred in the third quarter of 2008.
  - A $16 million increase in maintenance expense at the Cook Plant.
  - 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 Disposition of Assets, Net decreased $18 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 $23 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.
- Taxes Other Than Income Taxes increased $9 million primarily due to favorable adjustments to property tax returns recorded in the prior year.
- Carrying Costs Income increased $26 million primarily due to increased carrying cost income on cost deferrals in Virginia and Oklahoma.
- Interest Income increased $25 million primarily due to the favorable effect of claims for refund filed with the IRS.
- Other Income, Net increased $12 million primarily due to an increase in the equity component of AFUDC as a result of new generation projects.
- Interest and Other Charges increased $54 million primarily due to additional debt issued and higher interest rates on variable rate debt.
- Income Tax Expense increased $66 million due to an increase in pretax income.

AEP River Operations

Third Quarter of 2008 Compared to Third Quarter of 2007

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased to $11 million in 2008 from $18 million in 2007 primarily due to significant disruptions of ship arrivals and departures as the result of an oil spill in the New Orleans Harbor. Ship arrivals were further disrupted by the impacts of Hurricanes Gustav and Ike, which caused severe flooding on the Mississippi and Illinois Rivers. The decrease in income was also due to higher diesel fuel prices. Additionally, decreases in import demand and grain export demand have resulted in lower freight demand, partially offset by increased coal exports.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased to $21 million in 2008 from $40 million in 2007 primarily due to significant flooding on various inland waterways throughout 2008 and rising diesel fuel prices. Additionally, decreases in import demand and grain export demand have resulted in lower freight demand, largely the result of a slowing U.S. economy and a weak U.S. dollar. The impact of Hurricanes Gustav and Ike and the oil spill in the New Orleans Harbor, all of which occurred during the third quarter of 2008, also contributed to the unfavorable variance.

Generation and Marketing

Third Quarter of 2008 Compared to Third Quarter of 2007

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased to $16 million in 2008 from $3 million in 2007 primarily due to higher gross margins from its marketing activities and higher gross margins due to improved price realization, plant performance and hedging activities from its share of the Oklaunion Power Station.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased to $43 million in 2008 from $17 million in 2007 primarily due to higher gross margins from its marketing activities and higher gross margins due to improved price realization, plant performance and hedging activities from its share of the Oklaunion Power Station.

All Other

Third Quarter of 2008 Compared to Third Quarter of 2007

Loss Before Discontinued Operations and Extraordinary Loss from All Other increased to $10 million in 2008 from $2 million in 2007. The increase in the loss primarily relates to higher interest expenses due to the issuance of AEP Junior Subordinated Debentures and lower interest income from affiliates.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Income Before Discontinued Operations and Extraordinary Loss from All Other increased to $133 million in 2008 from a $1 million loss in 2007. In 2008, we had after-tax income of $163 million from a litigation settlement of a power purchase-and-sale agreement with TEM. The settlement was recorded as a pretax credit to Asset Impairments and Other Related Charges of $255 million in the accompanying Condensed Consolidated Statements of Income. In 2007, we had a $16 million pretax gain ($10 million, net of tax) on the sale of a portion of our investment in Intercontinental Exchange, Inc. (ICE).

AEP System Income Taxes

Income Tax Expense decreased $13 million in the third quarter of 2008 compared to the third quarter of 2007 primarily due to a decrease in pretax income.

Income Tax Expense increased $165 million in the nine-month period ended September 30, 2008 compared to the nine-month period ended September 30, 2007 primarily due to an increase in pretax income.

FINANCIAL CONDITION

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

Debt and Equity Capitalization

	September 30, 2008		December 31, 2007	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 16,007	56.6%	$ 14,994	58.1%
Short-term Debt	1,302	4.6	660	2.6
Total Debt	17,309	61.2	15,654	60.7
Common Equity	10,917	38.6	10,079	39.1
Preferred Stock	61	0.2	61	0.2
Total Debt and Equity Capitalization	$ 28,287	100.0%	$ 25,794	100.0%

Our ratio of debt to total capital increased from 60.7% to 61.2% in 2008 due to our issuance of debt to fund construction and our strategy to deal with the credit situation by drawing cash from our credit facilities.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. 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 and common stock.

Credit Markets

In recent months, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting our access to capital, our liquidity and our cost of capital. The uncertainties in the credit markets could have significant implications on our subsidiaries since they rely on continuing access to capital to fund operations and capital expenditures. The current credit markets are constraining our ability to issue new debt, including commercial paper, and refinance existing debt.

We believe that we have adequate liquidity under our credit facilities. In September 2008, in response to the bankruptcy of certain companies and tightening of credit markets, we borrowed $600 million under our credit lines to assure that cash is available to meet our working capital needs. In October 2008, we borrowed an additional $1.4 billion under our existing credit facilities. We took this proactive step to enhance our cash position during this period of market disruptions.

We cannot predict the length of time the current credit situation will continue or the impact on our future operations and our ability to issue debt at reasonable interest rates. However, when market conditions improve, we plan to repay the amounts drawn under the credit facilities and issue other long-term debt. If there is not an improvement in access to capital, we believe that we have adequate liquidity to support our planned business operations and construction program through 2009.

In the first quarter of 2008, due to the exposure that bond insurers like Ambac Assurance Corporation and Financial Guaranty Insurance Co. had in connection with developments in the subprime credit market, the credit ratings of those insurers were downgraded or placed on negative outlook. These market factors contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions for tax-exempt long-term debt sold at auction rates, including auctions of our tax-exempt long-term debt. Consequently, we chose to exit the auction-rate debt market. Through September 30, 2008, we reduced our outstanding auction rate securities by $1.2 billion. As of September 30, 2008, we had $272 million outstanding of tax-exempt long-term debt sold at auction rates (rates range between 4.353% and 13%) that reset every 35 days. Approximately $218 million of this debt relates to a lease structure with JMG that we are unable to refinance at this time. In order to refinance this debt, we need the lessor's consent. This debt is insured by the previously AAA-rated bond insurers. 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. We plan to continue the conversion and refunding process to other permitted modes, including term-put structures, variable-rate and fixed-rate structures, as opportunities arise. As of September 30, 2008, $367 million of the prior auction rate debt was issued in a weekly variable rate mode supported by letters of credit at variable rates ranging from 6.5% to 8.25%, $495 million was issued at fixed rates ranging from 4.5% to 5.625% and trustees held, on our behalf, approximately $330 million of our reacquired auction rate tax-exempt long-term debt which we plan to reissue to the public as market conditions permit.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At September 30, 2008, our available liquidity was approximately $3 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 (a)	April 2012
Revolving Credit Facility	627 (a)	April 2011
Revolving Credit Facility	338 (a)	April 2009
Total	3,919	
Short-term Investments	490	
Cash and Cash Equivalents	338	
Total Liquidity Sources	4,747	
Less: AEP Commercial Paper Outstanding	701	
Cash Drawn on Credit Facilities	591	
Letters of Credit Drawn	439	
Net Available Liquidity	$ 3,016	

(a) Reduced by Lehman Brothers Holdings Inc.'s commitment amount of $81 million following its bankruptcy.

The revolving credit facilities for commercial paper backup were structured as two $1.5 billion credit facilities which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $46 million following its bankruptcy. In March 2008, the credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit.

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of September 30, 2008, we had credit facilities totaling $3 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during the first nine months of 2008 was $1.2 billion. The weighted-average interest rate of our commercial paper during the first nine months of 2008 was 3.25%.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, we may issue letters of credit. As of September 30, 2008, $372 million of letters of credit were issued under the 3-year credit agreement to support variable rate demand notes.

Investments in Auction-Rate Securities

Prior to June 30, 2008, we sold all of our investment in auction-rate securities at par.

Sale of Receivables

In October 2008, we renewed our sale of receivables agreement. The sale of receivables agreement provides a commitment of $600 million from bank conduits to purchase receivables. This agreement will expire in October 2009.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements, including the new agreements entered into in April 2008, contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At September 30, 2008, this contractually-defined percentage was 57.3%. Nonperformance of these covenants could result in an event of default under these credit agreements. At September 30, 2008, 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 permit the lenders to declare the outstanding amounts payable.

Our 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 September 30, 2008, 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. The Board of Directors declared a quarterly dividend of $0.41 per share in October 2008. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. We have the option to defer interest payments on the $315 million of AEP Junior Subordinated Debentures issued in March 2008 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 net income, cash flows, financial condition or limit any dividend payments in the foreseeable future.

Credit Ratings

In the first quarter of 2008, Moody's changed its outlook from stable to negative for APCo, SWEPCo, OPCo and TCC and affirmed its stable outlook for AEP and our other rated subsidiaries. Also in the first quarter, Fitch downgraded PSO and SWEPCo from A- to BBB+ for senior unsecured debt. In May 2008, Fitch revised APCo's outlook from stable to negative. Our current credit ratings are as follows:

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

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

Cash Flow

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

	Nine Months Ended September 30, 2008	2007
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 178	$ 301
Net Cash Flows from Operating Activities	2,053	1,630
Net Cash Flows Used for Investing Activities	(3,061)	(2,935)
Net Cash Flows from Financing Activities	1,168	1,200
Net Increase (Decrease) in Cash and Cash Equivalents	160	(105)
Cash and Cash Equivalents at End of Period	$ 338	$ 196

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

	Nine Months Ended September 30, 2008	2007
	(in millions)	
Net Income	$ 1,228	$ 858
Less: Discontinued Operations, Net of Tax	(1)	(2)
Income Before Discontinued Operations	1,227	856
Depreciation and Amortization	1,123	1,144
Other	(297)	(370)
Net Cash Flows from Operating Activities	$ 2,053	$ 1,630

Net Cash Flows from Operating Activities increased in 2008 primarily due to the TEM settlement.

Net Cash Flows from Operating Activities were $2.1 billion in 2008 consisting primarily of Income Before Discontinued Operations of $1.2 billion and $1.1 billion of noncash Depreciation and Amortization. Other represents 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 an increase in under-recovered fuel reflecting higher coal and natural gas prices.

Net Cash Flows from Operating Activities were $1.6 billion in 2007 consisting primarily of Income Before Discontinued Operations of $856 million and $1.1 billion of noncash Depreciation and Amortization. Other represents items that had a prior 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 a number of items, the most significant of which relates primarily to the Texas CTC refund of fuel over-recovery.

Investing Activities

	Nine Months Ended September 30, 2008	2007
	(in millions)	
Construction Expenditures	$ (2,576)	$ (2,595)
Purchases/Sales of Investment Securities, Net	(474)	217
Acquisition of Assets	(97)	(512)
Proceeds from Sales of Assets	83	78
Other	3	(123)
Net Cash Flows Used for Investing Activities	$ (3,061)	$ (2,935)

Net Cash Flows Used for Investing Activities were $3.1 billion in 2008 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2007 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan. We paid $512 million to purchase gas-fired generating units to acquire capacity at a cost below that of building a new, comparable plant.

In our normal course of business, we purchase and sell investment securities with cash available for short-term investments including the cash drawn against our credit facilities in 2008. We also purchase and sell investment securities within our nuclear trusts.

We forecast approximately $1.2 billion of construction expenditures for the remainder of 2008. 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.

Financing Activities

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(in millions)	
Issuance of Common Stock	$ 106	$ 116
Issuance/Retirement of Debt, Net	1,621	1,623
Dividends Paid on Common Stock	(494)	(467)
Other	(65)	(72)
Net Cash Flows from Financing Activities	$ 1,168	$ 1,200

Net Cash Flows from Financing Activities in 2008 were $1.2 billion primarily due to the issuance of additional debt including $315 million of Junior Subordinated Debentures and a net increase of $1.3 billion in outstanding Senior Unsecured Notes partially offset, by the reacquisition of a net $370 million of Pollution Control Bonds and $125 million of Securitization Bonds. In September 2008, we borrowed $600 million under our credit agreements. See Note 9 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities in 2007 were $1.2 billion primarily due to issuing $1.9 billion of debt securities including $1 billion of new debt for plant acquisitions and construction and increasing short-term commercial paper borrowings.

Off-balance Sheet Arrangements

Under a limited set of circumstances, we enter into off-balance sheet arrangements to accelerate cash collections, reduce operational expenses and spread 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. Our significant off-balance sheet arrangements are as follows:

	September 30, 2008	December 31, 2007
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ 555	$ 507
Rockport Plant Unit 2 Future Minimum Lease Payments	2,142	2,216
Railcars Maximum Potential Loss From Lease Agreement	26	30

For complete information on each of these off-balance sheet arrangements see the "Off-balance Sheet Arrangements" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2007 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2007 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in “Cash Flow” above and the drawdowns and standby letters of credit discussed in “Liquidity” above.

SIGNIFICANT FACTORS

We continue to be involved in various matters described in the “Significant Factors” section of “Management’s Financial Discussion and Analysis of Results of Operations” in our 2007 Annual Report. The 2007 Annual Report should be read in conjunction with this report in order to understand significant factors which have not materially changed in status since the issuance of our 2007 Annual Report, but may have a material impact on our future net income, cash flows and financial condition.

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amends the restructuring law effective July 31, 2008 and requires electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities may file an ESP with a fuel cost recovery mechanism. Electric utilities also have an option to file a Market Rate Offer (MRO) for generation pricing. An MRO, from the date of its commencement, could transition CSPCo and OPCo to full market rates no sooner than six years and no later than ten years after the PUCO approves an MRO. The PUCO has the authority to approve or modify the utilities’ ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than the MRO. Both alternatives involve a “substantially excessive earnings” test based on what public companies, including other utilities with similar risk profiles, earn on equity. Management has preliminarily concluded, pending the outcome of the ESP proceeding, that CSPCo’s and OPCo’s generation/supply operations are not subject to cost-based rate regulation accounting. However, if a fuel cost recovery mechanism is implemented within the ESP, CSPCo’s and OPCo’s fuel and purchased power operations would be subject to cost-based rate regulation accounting. Management is unable to predict the financial statement impact of the restructuring legislation until the PUCO acts on specific proposals made by CSPCo and OPCo in their ESPs.

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file an optional MRO. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism (which excludes off-system sales) that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The increases in customer bills related to the fuel-purchased power cost recovery mechanism would be phased-in over the three year period from 2009 through 2011. If the ESP is approved as filed, effective with January 2009 billings, CSPCo and OPCo will defer any fuel cost under-recoveries and related carrying costs for future recovery. The under-recoveries and related carrying costs that exist at the end of 2011 will be recovered over seven years from 2012 through 2018. In addition to the fuel cost recovery mechanisms, the requested increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for distribution reliability costs and for unexpected non-fuel generation costs. The filings also include programs for smart metering initiatives and economic development and mandated energy efficiency and peak demand reduction programs. In September 2008, the PUCO issued a finding and order tentatively adopting rules governing MRO and ESP applications. CSPCo and OPCo filed their ESP applications based on proposed rules and requested waivers for portions of the proposed rules. The PUCO denied the waiver requests in September 2008 and ordered CSPCo and OPCo to submit information consistent with the tentative rules. In October 2008, CSPCo and OPCo submitted additional information related to proforma financial statements and information concerning CSPCo and OPCo’s fuel procurement process. In October 2008, CSPCo and OPCo filed an application for rehearing with the PUCO to challenge certain aspects of the proposed rules.

Within the ESPs, CSPCo and OPCo would also recover existing regulatory assets of $46 million and $38 million, respectively, for customer choice implementation and line extension carrying costs. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $30 million and $21 million, respectively. Such costs would be recovered over an 8-year period beginning January 2011. Hearings are scheduled for November 2008 and an order is expected in the fourth quarter of 2008. If an order is not received prior to January 1, 2009, CSPCo and OPCo have requested retroactive application of the new rates back to January 1, 2009 upon approval. Failure of the PUCO to ultimately approve the recovery of the regulatory assets would have an adverse effect on future net income and cash flows.

Cook Plant Unit 1 Fire and Shutdown

Cook Plant Unit 1 (Unit 1) is a 1,030 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations likely caused by blade failure which resulted in a fire on the electric generator. This equipment is in the turbine building and is separate and isolated from the nuclear reactor. The steam turbines that caused the vibration were installed in 2006 and are under warranty from the vendor. The warranty provides for the replacement of the turbines if the damage was caused by a defect in the design or assembly of the turbines. I&M is also working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and turbine vendor to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. We cannot estimate the ultimate costs of the outage at this time. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Our preliminary analysis indicates that Unit 1 could resume operations as early as late first quarter/early second quarter of 2009 or as late as the second half of 2009, depending upon whether the damaged components can be repaired or whether they need to be replaced.

I&M maintains property insurance through NEIL with a $1 million deductible. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12 week deductible period, I&M is entitled to weekly payments of $3.5 million during the outage period for a covered loss. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

TCC Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized its net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds over a period ending in 2020. TCC has refunded its net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Cash paid for these CTC refunds for the nine months ended September 30, 2008 and 2007 was $75 million and $207 million, respectively. TCC appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items. Municipal customers and other intervenors also appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries.

In March 2007, the Texas District Court judge hearing the appeals of the true-up order affirmed the PUCT's April 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs and remanded this matter to the PUCT for further consideration. The district court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness.

TCC, the PUCT and intervenors appealed the district court decision to the Texas Court of Appeals. In May 2008, the Texas Court of Appeals affirmed the district court decision in all but one major respect. It reversed the district court's unfavorable decision finding that the PUCT erred by applying an invalid rule to determine the carrying cost rate. The favorable commercial unreasonableness decision was not reversed. The Texas Court of Appeals denied intervenors' motion for rehearing. In May 2008, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court.

Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC ultimately succeeds in its appeals, it could have a material favorable effect on future net income, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals it could have a substantial adverse effect on future net income, cash flows and financial condition.

New Generation

In 2008, AEP completed or is in various stages of construction of the following generation facilities:

Operating Company	Project Name		Location	Total Projected Cost (a)	CWIP (b)	Fuel Type	Plant Type	Nominal MW Capacity	Commercial Operation Date (Projected)
				(in millions)	(in millions)				
PSO	Southwestern	(c)	Oklahoma	$ 56	$ -	Gas	Simple-cycle	150	2008
PSO	Riverside	(d)	Oklahoma	58	-	Gas	Simple-cycle	150	2008
AEGCo	Dresden	(e)	Ohio	309(h)	149	Gas	Combined-cycle	580	2010(h)
SWEPCo	Stall		Louisiana	378	158	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(f)	Arkansas	1,522(f)	448	Coal	Ultra-supercritical	600(f)	2012
APCo	Mountaineer	(g)	West Virginia	(g)		Coal	IGCC	629	(g)
CSPCo/OPCo	Great Bend	(g)	Ohio	(g)		Coal	IGCC	629	(g)

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) Southwestern Units were placed in service on February 29, 2008.
(d) The final Riverside Unit was placed in service on June 15, 2008.
(e) In September 2007, AEGCo purchased the partially completed Dresden Plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the "Total Projected Cost" section above.
(f) SWEPCo plans to own approximately 73%, or 440 MW, totaling $1.1 billion in capital investment. The increase in the cost estimate disclosed in the 2007 Annual Report relates to cost escalations due to the delay in receipt of permits and approvals. See "Turk Plant" section below.
(g) Construction of IGCC plants are pending necessary permits and regulatory approval. See "IGCC Plants" section below.
(h) Projected completion date of the Dresden Plant is currently under review. To the extent that the completion date is delayed, the total projected cost of the Dresden Plant could change.

Turk Plant

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant.

In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the $1.5 billion projected construction cost, excluding AFUDC, (b) capping CO_2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. An intervenor filed a motion for rehearing seeking reversal of the PUCT's decision. SWEPCo filed a motion for rehearing stating that the two cost cap restrictions are unlawful. In September 2008, the motions for rehearing were denied. In October 2008, SWEPCo appealed the PUCT's order regarding the two cost cap restrictions. If the cost cap restrictions are upheld and construction or emissions costs exceed the restrictions, it could have a material adverse impact on future net income and cash flows. In October 2008, an intervenor filed an appeal contending that the PUCT's grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

SWEPCo is also working with the Arkansas Department of Environmental Quality for the approval of an air permit and the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. Once SWEPCo receives the air permit, they will commence construction. A request to stop pre-construction activities at the site was filed in federal court by the same Arkansas landowners who appealed the APSC decision to the Arkansas State Court of Appeals. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In January 2008 and July 2008, SWEPCo filed applications for authority with the APSC to construct transmission lines necessary for service from the Turk Plant. Several landowners filed for intervention status and one landowner also contended he should be permitted to re-litigate Turk Plant issues, including the need for the generation. The APSC granted their intervention but denied the request to re-litigate the Turk Plant issues. The landowner filed an appeal to the Arkansas State Court of Appeals in June 2008.

The Arkansas Governor's Commission on Global Warming is scheduled to issue its final report to the Governor by November 1, 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. If legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's proposal to build the Turk Plant.

If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of September 30, 2008, SWEPCo has capitalized approximately $448 million of expenditures and has significant contractual construction commitments for an additional $771 million. As of September 30, 2008, if the plant had been cancelled, cancellation fees of $61 million would have been required in order to terminate these construction commitments. If the Turk Plant does not receive all necessary approvals on reasonable terms and SWEPCo cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

IGCC Plants

The construction of the West Virginia and Ohio IGCC plants are pending necessary permits and regulatory approvals. In May 2008, the Virginia SCC denied APCo's request to reconsider the Virginia SCC's previous denial of APCo's request to recover initial costs associated with a proposed IGCC plant in West Virginia. In July 2008, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed regarding its earlier approval of the IGCC plant. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expenses being incurred and certification of the IGCC plant prior to July 2010. Through September 30, 2008, APCo deferred for future recovery preconstruction IGCC costs of $19 million. If the West Virginia IGCC plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

In Ohio, CSPCo and OPCo continue to pursue the ultimate construction of the IGCC plant. In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all Phase 1 cost recoveries be refunded to Ohio ratepayers with interest. CSPCo and OPCo filed a response with the PUCO that argued the Ohio Consumers' Counsel's motion was without legal merit and contrary to past precedent. If CSPCo and OPCo were required to refund some or all of the $24 million collected for IGCC pre-construction costs and those costs were not recoverable in another jurisdiction in connection with the construction of an IGCC plant, it would have an adverse effect on future net income and cash flows.

<u>Litigation</u>

In the ordinary course of business, we, along with our subsidiaries, are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases that have a probable likelihood of loss and if the loss amount can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters, Note 6 – Commitments, Guarantees and Contingencies and the "Litigation" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2007 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies included herein. Adverse results in these proceedings have the potential to materially affect our net income.

Environmental Litigation

<u>New Source Review (NSR) Litigation:</u> The Federal EPA, a number of states and certain special interest groups filed complaints alleging that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities, including Cincinnati Gas & Electric Company, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. (Duke), modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA.

In 2007, the AEP System settled their complaints under a consent decree. CSPCo jointly-owns Beckjord and Stuart Stations with Duke and DP&L. A jury trial in May 2008 returned a verdict of no liability at the jointly-owned Beckjord unit. In October 2008, the court approved a settlement in the citizen suit action filed by Sierra Club against the jointly-owned units at Stuart Station. Under the settlement, the joint-owners of Stuart Station agreed to certain emission targets related to NO_x, SO_2 and PM. We also agreed to make energy efficiency and renewable energy commitments that are conditioned on 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.

Environmental Matters

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

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

In addition, we are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of spent nuclear fuel and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements to reduce CO_2 and other greenhouse gas (GHG) emissions to address concerns about global climate change. All of these matters are discussed in the "Environmental Matters" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2007 Annual Report.

Clean Air Act Requirements

As discussed in the 2007 Annual Report under "Clean Air Act Requirements," various states and environmental organizations challenged the Clean Air Mercury Rule (CAMR) in the D. C. Circuit Court of Appeals. The court ruled that the Federal EPA's action delisting fossil fuel-fired power plants did not conform to the procedures specified in the CAA. The court vacated and remanded the model federal rules for both new and existing coal-fired power plants to the Federal EPA. The Federal EPA filed a petition for review by the U.S. Supreme Court. We are unable to predict the outcome of this appeal or how the Federal EPA will respond to the remand. In addition, in 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR), that requires further reductions in SO_2 and NO_x emissions and assists states developing new state implementation plans to meet 1997 national ambient air quality standards (NAAQS). CAIR reduces regional emissions of SO_2 and NO_x (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO_2 by 50% by 2010, and by 65% by 2015. NO_x emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70% from current levels by 2015. Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals vacated the CAIR and remanded the rule to the Federal EPA. The Federal EPA and other parties petitioned for rehearing. We are unable to predict the outcome of the rehearing petitions or how the Federal EPA will respond to the remand which could be stayed or appealed to the U.S. Supreme Court. The Federal EPA also issued revised NAAQS for both ozone and $PM_{2.5}$ that are more stringent than the 1997 standards used to establish CAIR, which could increase the levels of SO_2 and NO_x reductions required from our facilities.

In anticipation of compliance with CAIR in 2009, I&M purchased $9 million of annual CAIR NO_x allowances which are included in Deferred Charges and Other on our Condensed Consolidated Balance Sheet as of September 30, 2008. The market value of annual CAIR NO_x allowances decreased following this court decision. However, our weighted-average cost of these allowances is below market. If CAIR remains vacated, management intends to seek partial recovery of the cost of purchased allowances. Any unrecovered portion would have an adverse effect on future net income and cash flows. None of AEP's other subsidiaries purchased any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to our facilities under the Acid Rain Program and the NO_x state implementation plan (SIP) Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

It is too early to determine the full implication of these decisions on our environmental compliance strategy. However, independent obligations under the CAA, including obligations under future state implementation plan submittals, and actions taken pursuant to our settlement of the NSR enforcement action, are consistent with the actions included in our least-cost CAIR compliance plan. Consequently, we do not anticipate making any immediate changes in our near-term compliance plans as a result of these court decisions.

Global Climate Change

In July 2008, the Federal EPA issued an advance notice of proposed rulemaking (ANPR) that requests comments on a wide variety of issues the agency is considering in formulating its response to the U.S. Supreme Court's decision in *Massachusetts v. EPA*. In that case, the court determined that CO_2 is an "air pollutant" and that the Federal EPA has authority to regulate mobile sources of CO_2 emissions under the CAA if appropriate findings are made. The Federal EPA has identified a number of issues that could affect stationary sources, such as electric generating plants, if the necessary findings are made for mobile sources, including the potential regulation of CO_2 emissions for both new and existing stationary sources under the NSR programs of the CAA. We plan to submit comments and participate in any subsequent regulatory development processes, but are unable to predict the outcome of the Federal EPA's administrative process or its impact on our business. Also, additional legislative measures to address CO_2 and other GHGs have been introduced in Congress, and such legislative actions could impact future decisions by the Federal EPA on CO_2 regulation.

In addition, the Federal EPA issued a proposed rule for the underground injection and storage of CO_2 captured from industrial processes, including electric generating facilities, under the Safe Drinking Water Act's Underground Injection Control (UIC) program. The proposed rules provide a comprehensive set of well siting, design, construction, operation, closure and post-closure care requirements. We plan to submit comments and participate in any subsequent regulatory development process, but are unable to predict the outcome of the Federal EPA's administrative process or its impact on our business. Permitting for our demonstration project at the Mountaineer Plant will proceed under the existing UIC rules.

Clean Water Act Regulations

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

In January 2007, the Second Circuit Court of Appeals issued a decision remanding significant portions of the rule to the Federal EPA. In July 2007, the Federal EPA suspended the 2004 rule, except for the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the 2004 rule is the applicable standard for permitting agencies pending finalization of revised rules by the Federal EPA. We cannot predict further action of the Federal EPA or what effect it may have on similar requirements adopted by the states. We sought further review and filed for relief from the schedules included in our permits.

In April 2008, the U.S. Supreme Court agreed to review decisions from the Second Circuit Court of Appeals that limit the Federal EPA's ability to weigh the retrofitting costs against environmental benefits. Management is unable to predict the outcome of this appeal.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2007 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157 “Fair Value Measurements” (SFAS 157), enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders’ equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity includes its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities” (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data. In February 2008, the FASB issued FSP SFAS 157-1 “Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13” which amends SFAS 157 to exclude SFAS 13 “Accounting for Leases” and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. In February 2008, the FASB issued FSP SFAS 157-2 “Effective Date of FASB Statement No. 157” which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). In October 2008, the FASB issued FSP SFAS 157-3 “Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active” which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, we recorded an immaterial transition adjustment to beginning retained earnings. The impact of considering our own credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption. We partially adopted SFAS 157 effective January 1, 2008. FSP SFAS 157-3 is effective upon issuance. We will fully adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP SFAS 157-2. We expect that the adoption of FSP SFAS 157-2 will have an immaterial impact on our financial statements. See “SFAS 157 “Fair Value Measurements” (SFAS 157)” section of Note 2.

In February 2007, the FASB issued SFAS 159 “The Fair Value Option for Financial Assets and Financial Liabilities” (SFAS 159), permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. The statement is applied prospectively upon adoption. We adopted SFAS 159 effective January 1, 2008. At adoption, we did not elect the fair value option for any assets or liabilities.

In March 2007, the FASB ratified EITF Issue No. 06-10 “Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements” (EITF 06-10), a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 “Employers' Accounting for Postretirement Benefits Other Than Pension” or Accounting Principles Board Opinion No. 12 “Omnibus Opinion – 1967” if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. We adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $16 million ($10 million, net of tax) to beginning retained earnings.

In June 2007, the FASB ratified the EITF Issue No. 06-11 “Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards” (EITF 06-11), consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, “Share-Based Payments.” Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. We adopted EITF 06-11 effective January 1, 2008. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after December 15, 2007. The adoption of this standard had an immaterial impact on our financial statements.

In April 2007, the FASB issued FSP FIN 39-1 “Amendment of FASB Interpretation No. 39” (FIN 39-1). It amends FASB Interpretation No. 39 “Offsetting of Amounts Related to Certain Contracts” by replacing the interpretation’s definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period. We adopted FIN 39-1 effective January 1, 2008. This standard changed our method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. Consequently, we reduced total assets and liabilities on the December 31, 2007 balance sheet by $47 million each. See “FSP FIN 39-1 “Amendment of FASB Interpretation No. 39” (FIN 39-1)” section of Note 2.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

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 liquidate 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, natural gas, coal and emissions and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy 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 President – AEP Utilities, 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.

The Committee of Chief Risk Officers (CCRO) adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. The following tables provide information on our risk management activities.

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

The following two tables summarize the various mark-to-market (MTM) positions included on our Condensed Consolidated Balance Sheet as of September 30, 2008 and the reasons for changes in our total MTM value included on our Condensed Consolidated Balance Sheet as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
September 30, 2008
(in millions)

	Utility Operations	Generation and Marketing	All Other	Sub-Total MTM Risk Management Contracts	MTM of Cash Flow and Fair Value Hedges	Collateral Deposits	Total
Current Assets	$ 246	$ 52	$ 43	$ 341	$ 25	$ (26)	$ 340
Noncurrent Assets	164	128	40	332	6	(24)	314
Total Assets	410	180	83	673	31	(50)	654
Current Liabilities	(209)	(65)	(47)	(321)	(18)	9	(330)
Noncurrent Liabilities	(69)	(57)	(43)	(169)	(4)	8	(165)
Total Liabilities	(278)	(122)	(90)	(490)	(22)	17	(495)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 132	$ 58	$ (7)	$ 183	$ 9	$ (33)	$ 159

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2008
(in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2007	$ 156	$ 43	$ (8)	$ 191
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(57)	4	1	(52)
Fair Value of New Contracts at Inception When Entered During the Period (a)	2	17	-	19
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	3	3	1	7
Changes in Fair Value Due to Market Fluctuations During the Period (c)	18	(9)	(1)	8
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	10	-	-	10
Total MTM Risk Management Contract Net Assets (Liabilities) at September 30, 2008	$ 132	$ 58	$ (7)	183
Net Cash Flow and Fair Value Hedge Contracts				9
Collateral Deposits				(33)
Ending Net Risk Management Assets at September 30, 2008				$ 159

(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.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Change in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

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

The following table presents the maturity, by year, of our net assets/liabilities, to give an indication of when these MTM amounts will settle and generate cash:

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of September 30, 2008
(in millions)

	Remainder 2008	2009	2010	2011	2012	After 2012 (f)	Total
Utility Operations:							
Level 1 (a)	$ (2)	$ (8)	$ -	$ -	$ -	$ -	$ (10)
Level 2 (b)	5	62	43	5	1	-	116
Level 3 (c)	(15)	2	(6)	1	1	-	(17)
Total	(12)	56	37	6	2	-	89
Generation and Marketing:							
Level 1 (a)	(1)	-	-	-	-	-	(1)
Level 2 (b)	(21)	2	11	12	11	20	35
Level 3 (c)	5	2	3	2	2	10	24
Total	(17)	4	14	14	13	30	58
All Other:							
Level 1 (a)	-	-	-	-	-	-	-
Level 2 (b)	(1)	(4)	(4)	2	-	-	(7)
Level 3 (c)	-	-	-	-	-	-	-
Total	(1)	(4)	(4)	2	-	-	(7)
Total:							
Level 1 (a)	(3)	(8)	-	-	-	-	(11)
Level 2 (b)	(17)	60	50	19	12	20	144
Level 3 (c) (d)	(10)	4	(3)	3	3	10	7
Total	(30)	56	47	22	15	30	140
Dedesignated Risk Management Contracts (e)	4	14	14	6	5	-	43
Total MTM Risk Management Contract Net Assets (Liabilities)	$ (26)	$ 70	$ 61	$ 28	$ 20	$ 30	$ 183

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.

(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

(d) A significant portion of the total volumetric position within the consolidated level 3 balance has been economically hedged.

(e) Dedesignated Risk Management Contracts are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized within Utility Operations Revenues over the remaining life of the contract.

(f) There is mark-to-market value of $30 million in individual periods beyond 2012. $14 million of this mark-to-market value is in 2013, $8 million is in 2014, $3 million is in 2015, $2 million is in 2016 and $3 million is in 2017.

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

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

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

We use foreign currency derivatives to lock in prices on certain forecasted transactions denominated in foreign currencies where deemed necessary, and designate qualifying instruments as cash flow hedges. We do not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2007 to September 30, 2008. The following table also indicates what portion of designated, effective hedges are expected to be reclassified into net income in the next 12 months. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Nine Months Ended September 30, 2008
(in millions)

	Power	Interest Rate and Foreign Currency	Total
Beginning Balance in AOCI, December 31, 2007	$ (1)	$ (25)	$ (26)
Changes in Fair Value	7	(5)	2
Reclassifications from AOCI for Cash Flow Hedges Settled	2	3	5
Ending Balance in AOCI, September 30, 2008	$ 8	$ (27)	$ (19)
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ 6	$ (5)	$ 1

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 initiated. We use Moody's Investors Service, Standard & Poor's and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. 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 September 30, 2008, our credit exposure net of collateral to sub investment grade counterparties was approximately 14.5%, 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). The increase from 5.4% at December 31, 2007 is primarily related to an increase in exposure with coal counterparties. Approximately 57% of our credit exposure net of collateral to sub investment grade counterparties is short-term exposure of less than one year. As of September 30, 2008, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
Investment Grade	$ 626	$ 42	$ 584	2	$ 146
Split Rating	14	-	14	2	14
Noninvestment Grade	81	8	73	2	66
No External Ratings:					
Internal Investment Grade	110	-	110	2	77
Internal Noninvestment Grade	46	-	46	2	40
Total as of September 30, 2008	$ 877	$ 50	$ 827	10	$ 343
Total as of December 31, 2007	$ 673	$ 42	$ 631	6	$ 74

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at September 30, 2008, 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 periods indicated:

VaR Model

Nine Months Ended September 30, 2008 (in millions)				Twelve Months Ended December 31, 2007 (in millions)			
End	High	Average	Low	End	High	Average	Low
$2	$3	$1	$1	$1	$6	$2	$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 historically-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translates into the largest potential mark-to-market loss. We then research the underlying positions, price moves and market events that created the most significant exposure.

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. The estimated EaR on our debt portfolio was $51 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2008 and 2007
(in millions, except per-share amounts and shares outstanding)
(Unaudited)

	Three Months Ended 2008	Three Months Ended 2007	Nine Months Ended 2008	Nine Months Ended 2007
REVENUES				
Utility Operations	$ 4,108	$ 3,423	$ 10,318	$ 9,127
Other	83	366	886	977
TOTAL	4,191	3,789	11,204	10,104
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,480	1,099	3,513	2,853
Purchased Electricity for Resale	394	358	1,023	895
Other Operation and Maintenance	1,010	964	2,870	2,783
Gain on Disposition of Assets, Net	(6)	(2)	(14)	(28)
Asset Impairments and Other Related Charges	-	-	(255)	-
Depreciation and Amortization	387	381	1,123	1,144
Taxes Other Than Income Taxes	189	191	578	565
TOTAL	3,454	2,991	8,838	8,212
OPERATING INCOME	737	798	2,366	1,892
Other Income:				
Interest and Investment Income	14	8	45	39
Carrying Costs Income	21	14	64	38
Allowance For Equity Funds Used During Construction	11	9	32	23
INTEREST AND OTHER CHARGES				
Interest Expense	216	216	670	615
Preferred Stock Dividend Requirements of Subsidiaries	1	1	2	2
TOTAL	217	217	672	617
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	566	612	1,835	1,375
Income Tax Expense	192	205	608	443
Minority Interest Expense	1	1	3	3
Equity Earnings of Unconsolidated Subsidiaries	1	1	3	6
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	374	407	1,227	935
DISCONTINUED OPERATIONS, NET OF TAX	-	-	1	2
INCOME BEFORE EXTRAORDINARY LOSS	374	407	1,228	937
EXTRAORDINARY LOSS, NET OF TAX	-	-	-	(79)
NET INCOME	$ 374	$ 407	$ 1,228	$ 858
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	402,286,779	399,222,569	401,535,661	398,412,473
BASIC EARNINGS PER SHARE				
Income Before Discontinued Operations and Extraordinary Loss	$ 0.93	$ 1.02	$ 3.06	$ 2.35
Discontinued Operations, Net of Tax	-	-	-	-
Income Before Extraordinary Loss	0.93	1.02	3.06	2.35
Extraordinary Loss, Net of Tax	-	-	-	(0.20)
TOTAL BASIC EARNINGS PER SHARE	$ 0.93	$ 1.02	$ 3.06	$ 2.15
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	403,910,309	400,215,911	402,925,534	399,552,630
DILUTED EARNINGS PER SHARE				
Income Before Discontinued Operations and Extraordinary Loss	$ 0.93	$ 1.02	$ 3.05	$ 2.34
Discontinued Operations, Net of Tax	-	-	-	0.01
Income Before Extraordinary Loss	0.93	1.02	3.05	2.35
Extraordinary Loss, Net of Tax	-	-	-	(0.20)
TOTAL DILUTED EARNINGS PER SHARE	$ 0.93	$ 1.02	$ 3.05	$ 2.15
CASH DIVIDENDS PAID PER SHARE	$ 0.41	$ 0.39	$ 1.23	$ 1.17

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2008 and December 31, 2007
(in millions)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 338	$ 178
Other Temporary Investments	670	365
Accounts Receivable:		
Customers	805	730
Accrued Unbilled Revenues	370	379
Miscellaneous	71	60
Allowance for Uncollectible Accounts	(59)	(52)
Total Accounts Receivable	1,187	1,117
Fuel, Materials and Supplies	1,018	967
Risk Management Assets	340	271
Regulatory Asset for Under-Recovered Fuel Costs	240	11
Margin Deposits	67	47
Prepayments and Other	124	70
TOTAL	3,984	3,026
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	20,948	20,233
Transmission	7,734	7,392
Distribution	12,561	12,056
Other (including nuclear fuel and coal mining)	3,633	3,445
Construction Work in Progress	3,516	3,019
Total	48,392	46,145
Accumulated Depreciation and Amortization	16,603	16,275
TOTAL - NET	31,789	29,870
OTHER NONCURRENT ASSETS		
Regulatory Assets	2,239	2,199
Securitized Transition Assets	2,080	2,108
Spent Nuclear Fuel and Decommissioning Trusts	1,292	1,347
Goodwill	76	76
Long-term Risk Management Assets	314	319
Employee Benefits and Pension Assets	479	486
Deferred Charges and Other	785	888
TOTAL	7,265	7,423
TOTAL ASSETS	$ 43,038	$ 40,319

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2008 and December 31, 2007
(Unaudited)

	2008	2007
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 1,447	$ 1,324
Short-term Debt	1,302	660
Long-term Debt Due Within One Year	682	792
Risk Management Liabilities	330	240
Customer Deposits	288	301
Accrued Taxes	564	601
Accrued Interest	235	235
Other	874	1,008
TOTAL	5,722	5,161
NONCURRENT LIABILITIES		
Long-term Debt	15,325	14,202
Long-term Risk Management Liabilities	165	188
Deferred Income Taxes	5,150	4,730
Regulatory Liabilities and Deferred Investment Tax Credits	2,827	2,952
Asset Retirement Obligations	1,090	1,075
Employee Benefits and Pension Obligations	672	712
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	132	139
Deferred Credits and Other	977	1,020
TOTAL	26,338	25,018
TOTAL LIABILITIES	32,060	30,179
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock – $6.50 Par Value Per Share:		

	2008	2007
Shares Authorized	600,000,000	600,000,000
Shares Issued	424,538,502	421,926,696

	2008	2007
(21,499,992 shares were held in treasury at September 30, 2008 and December 31, 2007)	2,760	2,743
Paid-in Capital	4,444	4,352
Retained Earnings	3,861	3,138
Accumulated Other Comprehensive Income (Loss)	(148)	(154)
TOTAL	10,917	10,079
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 43,038	$ 40,319

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2008 and 2007
(in millions)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 1,228	$ 858
Less: Discontinued Operations, Net of Tax	(1)	(2)
Income Before Discontinued Operations	1,227	856
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,123	1,144
Deferred Income Taxes	397	44
Extraordinary Loss, Net of Tax	-	79
Carrying Costs Income	(64)	(38)
Allowance for Equity Funds Used During Construction	(32)	(23)
Mark-to-Market of Risk Management Contracts	14	(7)
Amortization of Nuclear Fuel	72	48
Deferred Property Taxes	136	118
Fuel Over/Under-Recovery, Net	(284)	(133)
Gain on Sales of Assets and Equity Investments, Net	(14)	(28)
Change in Other Noncurrent Assets	(160)	(64)
Change in Other Noncurrent Liabilities	(74)	98
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(69)	(209)
Fuel, Materials and Supplies	(49)	(13)
Margin Deposits	(20)	39
Accounts Payable	77	(54)
Customer Deposits	(14)	36
Accrued Taxes, Net	(40)	(119)
Accrued Interest	(5)	22
Other Current Assets	(43)	(33)
Other Current Liabilities	(125)	(133)
Net Cash Flows from Operating Activities	2,053	1,630
INVESTING ACTIVITIES		
Construction Expenditures	(2,576)	(2,595)
Change in Other Temporary Investments, Net	106	(50)
Purchases of Investment Securities	(1,386)	(8,632)
Sales of Investment Securities	912	8,849
Acquisitions of Nuclear Fuel	(99)	(73)
Acquisitions of Assets	(97)	(512)
Proceeds from Sales of Assets	83	78
Other	(4)	-
Net Cash Flows Used for Investing Activities	(3,061)	(2,935)
FINANCING ACTIVITIES		
Issuance of Common Stock	106	116
Issuance of Long-term Debt	2,561	1,924
Change in Short-term Debt, Net	642	569
Retirement of Long-term Debt	(1,582)	(870)
Principal Payments for Capital Lease Obligations	(76)	(49)
Dividends Paid on Common Stock	(494)	(467)
Other	11	(23)
Net Cash Flows from Financing Activities	1,168	1,200
Net Increase (Decrease) in Cash and Cash Equivalents	160	(105)
Cash and Cash Equivalents at Beginning of Period	178	301
Cash and Cash Equivalents at End of Period	$ 338	$ 196
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 657	$ 549
Net Cash Paid for Income Taxes	126	363
Noncash Acquisitions Under Capital Leases	47	59
Noncash Acquisition of Land/Mineral Rights	42	-
Construction Expenditures Included in Accounts Payable at September 30,	373	265
Acquisition of Nuclear Fuel Included in Accounts Payable at September 30,	66	1
Noncash Assumption of Liabilities Related to Acquisitions of Darby, Lawrenceburg and Dresden Plants	-	8

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2008 and 2007
(in millions)
(Unaudited)

	Common Stock					
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	418	$ 2,718	$ 4,221	$ 2,696	$ (223)	$ 9,412
FIN 48 Adoption, Net of Tax				(17)		(17)
Issuance of Common Stock	3	21	95			116
Common Stock Dividends				(467)		(467)
Other			12			12
TOTAL						9,056
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Cash Flow Hedges, Net of Tax of $6					(11)	(11)
Securities Available for Sale, Net of Tax of $3					(5)	(5)
SFAS 158 Costs Established as a Regulatory Asset Related to the Reapplication of SFAS 71, Net of Tax of $6					11	11
NET INCOME				858		858
TOTAL COMPREHENSIVE INCOME						853
SEPTEMBER 30, 2007	421	$ 2,739	$ 4,328	$ 3,070	$ (228)	$ 9,909
DECEMBER 31, 2007	422	$ 2,743	$ 4,352	$ 3,138	$ (154)	$ 10,079
EITF 06-10 Adoption, Net of Tax of $6				(10)		(10)
SFAS 157 Adoption, Net of Tax of $0				(1)		(1)
Issuance of Common Stock	3	17	89			106
Common Stock Dividends				(494)		(494)
Other			3			3
TOTAL						9,683
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Cash Flow Hedges, Net of Tax of $4					7	7
Securities Available for Sale, Net of Tax of $5					(10)	(10)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $5					9	9
NET INCOME				1,228		1,228
TOTAL COMPREHENSIVE INCOME						1,234
SEPTEMBER 30, 2008	425	$ 2,760	$ 4,444	$ 3,861	$ (148)	$ 10,917

See Condensed Notes to Condensed Consolidated Financial Statements.

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed consolidated financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our net income, financial position and cash flows for the interim periods. The net income for the three and nine months ended September 30, 2008 are not necessarily indicative of results that may be expected for the year ending December 31, 2008. The accompanying condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2007 consolidated financial statements and notes thereto, which are included in our Annual Report on Form 10-K for the year ended December 31, 2007 as filed with the SEC on February 28, 2008.

Earnings Per Share

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

	Three Months Ended September 30,			
	2008		2007	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to Common Stock	$ 374		$ 407	
Average Number of Basic Shares Outstanding	402.3	$ 0.93	399.2	$ 1.02
Average Dilutive Effect of:				
Performance Share Units	1.3	-	0.5	-
Stock Options	0.1	-	0.3	-
Restricted Stock Units	0.1	-	0.1	-
Restricted Shares	0.1	-	0.1	-
Average Number of Diluted Shares Outstanding	403.9	$ 0.93	400.2	$ 1.02

	Nine Months Ended September 30,			
	2008		2007	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to Common Stock	$ 1,228		$ 858	
Average Number of Basic Shares Outstanding	401.5	$ 3.06	398.4	$ 2.15
Average Dilutive Effect of:				
Performance Share Units	1.0	(0.01)	0.6	-
Stock Options	0.2	-	0.4	-
Restricted Stock Units	0.1	-	0.1	-
Restricted Shares	0.1	-	0.1	-
Average Number of Diluted Shares Outstanding	402.9	$ 3.05	399.6	$ 2.15

The assumed conversion of our share-based compensation does not affect net earnings for purposes of calculating diluted earnings per share.

Options to purchase 146,900 and 83,550 shares of common stock were outstanding at September 30, 2008 and 2007, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the quarter-end market price of the common shares and, therefore, the effect would be antidilutive.

Supplementary Information

Related Party Transactions	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(in millions)		(in millions)	
AEP Consolidated Revenues – Utility Operations:				
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% owned)	$ (14)	$ (12)	$ (40)	$ (16)
AEP Consolidated Revenues – Other:				
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	7	7	21	24
AEP Consolidated Expenses – Purchased Energy for Resale:				
Ohio Valley Electric Corporation (43.47% Owned)	70	59	194	164
Sweeny Cogeneration Limited Partnership (a)	-	27	-	86

(a) In October 2007, we sold our 50% ownership in the Sweeny Cogeneration Limited Partnership.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. See "FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)" section of Note 2 for discussion of changes in netting certain balance sheet amounts. These reclassifications had no impact on our previously reported net income or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we thoroughly review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented in 2008 and standards issued but not implemented that we have determined relate to our operations.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It establishes how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. SFAS 141R requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period.

SFAS 141R is effective prospectively for business combinations with an acquisition date on or after the beginning of the first annual reporting period after December 15, 2008. Early adoption is prohibited. We will adopt SFAS 141R effective January 1, 2009 and apply it to any business combinations on or after that date.

SFAS 157 "Fair Value Measurements" (SFAS 157)

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity includes its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative

Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data.

In February 2008, the FASB issued FSP SFAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" (SFAS 157-1) which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" (SFAS 13) and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13.

In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2) which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

In October 2008, the FASB issued FSP SFAS 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active" which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The FSP was effective upon issuance. The adoption of this standard had no impact on our financial statements.

We partially adopted SFAS 157 effective January 1, 2008. We will fully adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP SFAS 157-2. We expect that the adoption of FSP SFAS 157-2 will have an immaterial impact on our financial statements. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, we recorded an immaterial transition adjustment to beginning retained earnings. The impact of considering our own credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption.

In accordance with SFAS 157, assets and liabilities are classified based on the inputs utilized in the fair value measurement. SFAS 157 provides definitions for two types of inputs: observable and unobservable. Observable inputs are valuation inputs that reflect the assumptions market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the reporting entity. Unobservable inputs are valuation inputs that reflect the reporting entity's own assumptions about the assumptions market participants would use in pricing the asset or liability developed based on the best information in the circumstances.

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 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).

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts, listed equities and U.S. government treasury securities that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 inputs are inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in level 1, OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market and certain non-exchange-traded debt securities.

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

Risk Management Contracts include exchange traded, OTC and bilaterally executed derivative contracts. Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within level 1. Other actively traded derivative fair values are verified using broker or dealer quotations, similar observable market transactions in either the listed or OTC markets, or valued using pricing models where significant valuation inputs are directly or indirectly observable in active markets. Derivative instruments, primarily swaps, forwards, and options that meet these characteristics are classified within level 2. Bilaterally executed agreements are derivative contracts entered into directly with third parties, and at times these instruments may be complex structured transactions that are tailored to meet the specific customer's energy requirements. Structured transactions utilize pricing models that are widely accepted in the energy industry to measure fair value. Generally, we use a consistent modeling approach to value similar instruments. 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 markets that are not active, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions or 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 in level 3. In certain instances, the fair values of the transactions that use internally developed model inputs, classified as level 3 are offset partially or in full, by transactions included in level 2 where observable market data exists for the offsetting transaction.

The following table sets 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 September 30, 2008. As required by SFAS 157, 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.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of September 30, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 271	$ -	$ -	$ 67	$ 338
Other Temporary Investments:					
Cash and Cash Equivalents (b)	$ 147	$ -	$ -	$ 22	$ 169
Debt Securities (c)	-	490	-	-	490
Equity Securities (d)	11	-	-	-	11
Total Other Temporary Investments	$ 158	$ 490	$ -	$ 22	$ 670
Risk Management Assets:					
Risk Management Contracts (e)	$ 41	$ 2,423	$ 75	$ (1,959)	$ 580
Cash Flow and Fair Value Hedges (e)	9	37	-	(15)	31
Dedesignated Risk Management Contracts (f)	-	-	-	43	43
Total Risk Management Assets	$ 50	$ 2,460	$ 75	$ (1,931)	$ 654
Spent Nuclear Fuel and Decommissioning Trusts:					
Cash and Cash Equivalents (g)	$ -	$ 4	$ -	$ 6	$ 10
Debt Securities (h)	-	837	-	-	837
Equity Securities (d)	445	-	-	-	445
Total Spent Nuclear Fuel and Decommissioning Trusts	$ 445	$ 841	$ -	$ 6	$ 1,292
Total Assets	$ 924	$ 3,791	$ 75	$ (1,836)	$ 2,954
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (e)	$ 52	$ 2,279	$ 68	$ (1,926)	$ 473
Cash Flow and Fair Value Hedges (e)	-	37	-	(15)	22
Total Risk Management Liabilities	$ 52	$ 2,316	$ 68	$ (1,941)	$ 495

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

(b) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.

(c) Amounts represent Variable Rate Demand Notes.

(d) Amounts represent publicly traded equity securities.

(e) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(f) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into Utility Operations Revenues over the remaining life of the contract.

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

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

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:

Three Months Ended September 30, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of July 1, 2008	$ (8)	$ -	$ -
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)	17	-	-
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(7)	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements	-	-	-
Transfers in and/or out of Level 3 (b)	(10)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	15	-	-
Balance as of September 30, 2008	$ 7	$ -	$ -

Nine Months Ended September 30, 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 Earnings (or Changes in Net Assets) (a)	-	-	-
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	4	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements	-	(118)	(17)
Transfers in and/or out of Level 3 (b)	(35)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(11)	-	-
Balance as of September 30, 2008	$ 7	$ -	$ -

(a) Included in revenues on our Condensed Consolidated Statements of Income.

(b) “Transfers in and/or out of Level 3” represent 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.

(c) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected on the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

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

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. The statement is applied prospectively upon adoption.

We adopted SFAS 159 effective January 1, 2008. At adoption, we did not elect the fair value option for any assets or liabilities.

SFAS 160 "Noncontrolling Interest 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. It 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.

SFAS 160 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. The statement is applied prospectively upon adoption. Early adoption is prohibited. Upon adoption, prior period financial statements will be restated for the presentation of the noncontrolling interest for comparability. We expect that the adoption of this standard will have an immaterial impact on our financial statements. We will adopt SFAS 160 effective January 1, 2009.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard is intended to improve upon the existing disclosure framework in SFAS 133.

SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008. We expect this standard to increase our disclosure requirements related to derivative instruments and hedging activities. It encourages retrospective application to comparative disclosure for earlier periods presented. We will adopt SFAS 161 effective January 1, 2009.

SFAS 162 "The Hierarchy of Generally Accepted Accounting Principles" (SFAS 162)

In May 2008, the FASB issued SFAS 162, clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP.

SFAS 162 is effective 60 days after the SEC approves the Public Company Accounting Oversight Board's amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." We expect the adoption of this standard will have no impact on our financial statements. We will adopt SFAS 162 when it becomes effective.

EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements" (EITF 06-10)

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pension" or Accounting Principles Board Opinion No. 12 "Omnibus Opinion – 1967" if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. We adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $16 million ($10 million, net of tax) to beginning retained earnings.

EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11)

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after December 15, 2007.

We adopted EITF 06-11 effective January 1, 2008. The adoption of this standard had an immaterial impact on our financial statements.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the EITF consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities.

EITF 08-5 is effective for the first reporting period beginning after December 15, 2008. It will be applied prospectively upon adoption with the effect of initial application included as a change in fair value of the liability in the period of adoption. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application. Early adoption is permitted. Although we have not completed our analysis, we expect that the adoption of this standard will have an immaterial impact on our financial statements. We will adopt this standard effective January 1, 2009.

FSP EITF 03-6-1 "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" (EITF 03-6-1)

In June 2008, the FASB issued EITF 03-6-1 addressing whether instruments granted in share-based payment transactions are participating securities prior to vesting and need to be included in earnings allocation in computing EPS under the two-class method described in SFAS 128 "Earnings per Share."

EITF 03-6-1 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. The statement is applied retrospectively upon adoption. Early adoption is prohibited. Upon adoption, prior period financial statements will be restated for comparability. Although we have not completed our analysis, we expect that the adoption of this standard will have an immaterial impact on our financial statements. We will adopt EITF 03-6-1 effective January 1, 2009.

FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161" (SFAS 133-1 and FIN 45-4)

In September 2008, the FASB issued SFAS 133-1 and FIN 45-4 as amendments to original statements SFAS 133 and FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Under the SFAS 133 requirements, the seller of a credit derivative shall disclose the following information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote:

(a) The nature of the credit derivative.
(b) The maximum potential amount of future payments.
(c) The fair value of the credit derivative.
(d) The nature of any recourse provisions and any assets held as collateral or by third parties.

Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk.

The standard is effective for interim and annual reporting periods ending after November 15, 2008. Upon adoption, the guidance will be prospectively applied. We expect that the adoption of this standard will have an immaterial impact on our financial statements but increase our FIN 45 guarantees disclosure requirements. We will adopt the standard effective December 31, 2008.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS 142, "Goodwill and Other Intangible Assets." The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

SFAS 142-3 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. Early adoption is prohibited. Upon adoption, the guidance within SFAS 142-3 will be prospectively applied to intangible assets acquired after the effective date. We expect that the adoption of this standard will have an immaterial impact on our financial statements. We will adopt SFAS 142-3 effective January 1, 2009.

FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)

In April 2007, the FASB issued FIN 39-1. It amends FASB Interpretation No. 39 "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

We adopted FIN 39-1 effective January 1, 2008. This standard changed our method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. Consequently, we reclassified the following amounts on the December 31, 2007 Condensed Consolidated Balance Sheet as shown:

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the September 2008 10-Q
		(in millions)	
Current Assets:			
Risk Management Assets	$ 286	$ (15)	$ 271
Margin Deposits	58	(11)	47
Long-term Risk Management Assets	340	(21)	319
Current Liabilities:			
Risk Management Liabilities	250	(10)	240
Customer Deposits	337	(36)	301
Long-term Risk Management Liabilities	189	(1)	188

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 September 30, 2008 balance sheet, we netted $50 million of cash collateral received from third parties against short-term and long-term risk management assets and $17 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

Future Accounting Changes

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

EXTRAORDINARY ITEM

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) during the second quarter of 2007 for the reestablishment of regulatory assets and liabilities related to our Virginia retail generation and supply operations. In 2000, we discontinued SFAS 71 regulatory accounting in our Virginia jurisdiction for retail generation and supply operations due to the passage of legislation for customer choice and deregulation.

3. RATE MATTERS

As discussed in the 2007 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2007 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2008 and updates the 2007 Annual Report.

Ohio Rate Matters

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amends the restructuring law effective July 31, 2008 and requires electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities may file an ESP with a fuel cost recovery mechanism. Electric utilities also have an option to file a Market Rate Offer (MRO) for generation pricing. A MRO, from the date of its commencement, could transition CSPCo and OPCo to full market rates no sooner than six years and no later than ten years after the PUCO approves a MRO.

The PUCO has the authority to approve or modify each utilities' ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than a MRO. Both alternatives involve a "substantially excessive earnings" test based on what public companies, including other utilities with similar risk profiles, earn on equity. Management has preliminarily concluded, pending the outcome of the ESP proceeding, that CSPCo's and OPCo's generation/supply operations are not subject to cost-based rate regulation accounting. However, if a fuel cost recovery mechanism is implemented within the ESP, CSPCo's and OPCo's fuel and purchased power operations would be subject to cost-based rate regulation accounting. Management is unable to predict the financial statement impact of the restructuring legislation until the PUCO acts on specific proposals made by CSPCo and OPCo in their ESPs.

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file an optional MRO. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism (which excludes off-system sales) that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The increases in customer bills related to the fuel-purchased power cost recovery mechanism would be phased-in over the three year period from 2009 through 2011. If the ESP is approved as filed, effective with January 2009 billings, CSPCo and OPCo will defer any fuel cost under-recoveries and related carrying costs for future recovery. The under-recoveries and related carrying costs that exist at the end of 2011 will be recovered over seven years from 2012 through 2018. In addition to the fuel cost recovery mechanisms, the requested increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for distribution reliability costs and for unexpected non-fuel generation costs. The filings also include programs for smart metering initiatives and economic development and mandated energy efficiency and peak demand reduction programs. In September 2008, the PUCO issued a finding and order tentatively adopting rules governing MRO and ESP applications. CSPCo and OPCo filed their ESP applications based on proposed rules and requested waivers for portions of the proposed rules. The PUCO denied the waiver requests in September 2008 and ordered CSPCo and OPCo to submit information consistent with the tentative rules. In October 2008, CSPCo and OPCo submitted additional information related to proforma financial statements and information concerning CSPCo and OPCo's fuel procurement process. In October 2008, CSPCo and OPCo filed an application for rehearing with the PUCO to challenge certain aspects of the proposed rules.

Within the ESPs, CSPCo and OPCo would also recover existing regulatory assets of $46 million and $38 million, respectively, for customer choice implementation and line extension carrying costs. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $30 million and $21 million, respectively. Such costs would be recovered over an 8-year period beginning January 2011. Hearings are scheduled for November 2008 and an order is expected in the fourth quarter of 2008. If an order is not received prior to January 1, 2009, CSPCo and OPCo have requested retroactive application of the new rates back to January 1, 2009 upon approval. Failure of the PUCO to ultimately approve the recovery of the regulatory assets would have an adverse effect on future net income and cash flows.

2008 Generation Rider and Transmission Rider Rate Settlement

On January 30, 2008, the PUCO approved a settlement agreement, among CSPCo, OPCo and other parties, under the additional average 4% generation rate increase and transmission cost recovery rider (TCRR) provisions of the RSP. The increase was to recover additional governmentally-mandated costs including incremental environmental costs. Under the settlement, the PUCO also approved recovery through the TCRR of increased PJM costs associated with transmission line losses of $39 million each for CSPCo and OPCo. As a result, CSPCo and OPCo established regulatory assets during the first quarter of 2008 of $12 million and $14 million, respectively, related to the future recovery of increased PJM billings previously expensed from June 2007 to December 2007 for transmission line losses. The PUCO also approved a credit applied to the TCRR of $10 million for OPCo and $8 million for CSPCo for a reduction in PJM net congestion costs. To the extent that collections for the TCRR recoveries are under/over actual net costs, CSPCo and OPCo will defer the difference as a regulatory asset or regulatory liability and adjust future customer billings to reflect actual costs, including carrying costs on the deferral. Under the terms of the settlement, although the increased PJM costs associated with transmission line losses will be recovered through the

TCRR, these recoveries will still be applied to reduce the annual average 4% generation rate increase limitation. In addition, the PUCO approved recoveries through generation rates of environmental costs and related carrying costs of $29 million for CSPCo and $5 million for OPCo. These RSP rate adjustments were implemented in February 2008.

Also, in February 2008, Ormet, a major industrial customer, filed a motion to intervene and an application for rehearing of the PUCO's January 2008 RSP order claiming the settlement inappropriately shifted $4 million in cost recovery to Ormet. In March 2008, the PUCO granted Ormet's motion to intervene. Ormet's rehearing application also was granted for the purpose of providing the PUCO with additional time to consider the issues raised by Ormet. Upon PUCO approval of an unrelated amendment to the Ormet contract, Ormet withdrew its rehearing application in August 2008.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the generation rates which may be a market-based standard service offer price for generation and the expected higher cost of operating and maintaining the plant, including a return on and return of the projected cost to construct the plant.

In June 2006, the PUCO issued an order approving a tariff to allow CSPCo and OPCo to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. During that period CSPCo and OPCo each collected $12 million in pre-construction costs and 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 within five years of the June 2006 PUCO order, all Phase 1 cost recoveries associated with items that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 pending further hearings.

In August 2006, intervenors filed four separate appeals of the PUCO's order in the IGCC proceeding. In March 2008, the Ohio Supreme Court issued its opinion affirming in part, and reversing in part the PUCO's order and remanded the matter back to the PUCO. The Ohio Supreme Court held that while there could be an opportunity under existing law to recover a portion of the IGCC costs in distribution rates, traditional rate making procedures would apply to the recoverable portion. The Ohio Supreme Court did not address the matter of refunding the Phase 1 cost recovery and declined to create an exception to its precedent of denying claims for refund of past recoveries from approved orders of the PUCO. In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all Phase 1 costs be refunded to Ohio ratepayers with interest because the Ohio Supreme Court invalidated the underlying foundation for the Phase 1 recovery. CSPCo and OPCo filed a motion with the PUCO that argued the Ohio Consumers' Counsel's motion was without legal merit and contrary to past precedent. If CSPCo and OPCo were required to refund the $24 million collected and those costs were not recoverable in another jurisdiction in connection with the construction of an IGCC plant, it would have an adverse effect on future net income and cash flows.

As of December 31, 2007, the cost of the plant was estimated at $2.7 billion. The estimated cost of the plant has continued to increase significantly. Management continues to pursue the ultimate construction of the IGCC plant. CSPCo and OPCo will not start construction of the IGCC plant until sufficient assurance of regulatory cost recovery exists.

Ormet

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load, in accordance with a settlement agreement approved by the PUCO. The settlement agreement allows for the recovery in 2007 and 2008 of the difference between the $43 per MWH Ormet pays for power and a PUCO-approved market price, if higher. The PUCO approved a $47.69 per MWH market price for 2007 and the difference was recovered through the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) excess deferred tax regulatory liability resulting from an Ohio franchise tax phase-out recorded in 2005.

CSPCo and OPCo each amortized $8 million of this regulatory liability to income for the nine months ended September 30, 2008 based on the previously approved 2007 price of $47.69 per MWH. In December 2007, CSPCo and OPCo submitted for approval a market price of $53.03 per MWH for 2008. The PUCO has not yet approved the 2008 market price. If the PUCO approves a market price for 2008 below $47.69, it could have an adverse effect on future net income and cash flows. A price above $47.69 should result in a favorable effect. If CSPCo and OPCo serve the Ormet load after 2008 without any special provisions, they could experience incremental costs to acquire additional capacity to meet their reserve requirements and/or forgo more profitable market-priced off-system sales.

Hurricane Ike

In September 2008, the service territories of CSPCo and OPCo were impacted by strong winds from the remnants of Hurricane Ike. CSPCo and OPCo incurred approximately $18 million and $13 million, respectively, in incremental distribution operation and maintenance costs related to service restoration efforts. Under the current RSP, CSPCo and OPCo can seek a distribution rate adjustment to recover incremental distribution expenses related to major storm service restoration efforts. In September 2008, CSPCo and OPCo established regulatory assets of $17 million and $10 million, respectively, for the incremental distribution operation and maintenance costs related to service restoration efforts. The regulatory assets represent the excess above the average of the last three years of distribution storm expenses excluding Hurricane Ike, which was the methodology used by the PUCO to determine the recoverable amount of storm restoration expenses in the most recent 2006 PUCO storm damage recovery decision. Prior to December 31, 2008, which is the expiration of the RSP, CSPCo and OPCo will file for recovery of the regulatory assets. As a result of the past favorable treatment of storm restoration costs and the favorable RSP provisions, management believes the recovery of the regulatory assets is probable. If these regulatory assets are not recoverable, it would have an adverse effect on future net income and cash flows.

Texas Rate Matters

TEXAS RESTRUCTURING

TCC Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized its net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds over a period ending in 2020. TCC has refunded its net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Cash paid for these CTC refunds for the nine months ended September 30, 2008 and 2007 was $75 million and $207 million, respectively. TCC appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items. The significant items appealed by TCC are:

- The PUCT ruling that TCC did not comply with the Texas Restructuring Legislation and PUCT rules regarding the required auction of 15% of its Texas jurisdictional installed capacity, which led to a significant disallowance of capacity auction true-up revenues.
- The PUCT ruling that TCC acted in a manner that was commercially unreasonable, because TCC failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and TCC bundled out-of-the-money gas units with the sale of its coal unit, which led to the disallowance of a significant portion of TCC’s net stranded generation plant costs.
- Two federal matters regarding the allocation of off-system sales related to fuel recoveries and a potential tax normalization violation.

Municipal customers and other intervenors also appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries.

In March 2007, the Texas District Court judge hearing the appeals of the true-up order affirmed the PUCT's April 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs and remanded this matter to the PUCT for further consideration. The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness.

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. In May 2008, the Texas Court of Appeals affirmed the District Court decision in all but one major respect. It reversed the District Court's unfavorable decision finding that the PUCT erred by applying an invalid rule to determine the carrying cost rate. The favorable commercial unreasonableness decision was not reversed. The Texas Court of Appeals denied intervenors' motion for rehearing. In May 2008, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court.

Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC ultimately succeeds in its appeals, it could have a material favorable effect on future net income, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals it could have a substantial adverse effect on future net income, cash flows and financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

Appeals remain outstanding related to the stranded costs true-up and related orders regarding whether the PUCT may require TCC to refund certain tax benefits to customers. The PUCT agreed to allow TCC to defer $103 million of the CTC other true-up items to refund to customers ($61 million in present value of the tax benefits associated with TCC's generation assets plus $42 million of related carrying costs) pending resolution of whether the PUCT's securitization refund is an IRS normalization violation. The deferral of the CTC refund negates the securitization reduction pending resolution of the normalization violation issue.

In March 2008, the IRS issued final regulations addressing Accumulated Deferred Investment Tax Credit (ADITC) and Excess Deferred Federal Income Tax (EDFIT) normalization requirements. Consistent with a Private Letter Ruling TCC received in 2006, the regulations clearly state that TCC will sustain a normalization violation if the PUCT orders TCC to flow the tax benefits to customers. TCC notified the PUCT that the final regulations were issued. In May 2008, as requested by the PUCT, the Texas Court of Appeals ordered a remand of the tax normalization issue for the consideration of this additional evidence.

TCC expects that the PUCT will allow TCC to retain and not refund these amounts. This will have a favorable effect on future net income and cash flows as TCC will record the ADITC and EDFIT tax benefits in income due to the sale of the generating plants that generated the tax benefits. Since management expects that the PUCT will allow TCC to retain the deferred CTC refund amounts in order to avoid an IRS normalization violation, management has not accrued any related interest expense should TCC ultimately be required to refund these amounts. If accrued, management estimates the interest expense would be approximately $2 million higher for the period July 1, 2008 through September 30, 2008 based on a CTC interest rate of 7.5%.

However, if the PUCT orders TCC to flow the tax benefits to customers, thereby causing TCC to violate the IRS' normalization regulations, it could result in TCC's repayment to the IRS of ADITC on all property, including transmission and distribution property. This amount approximates $103 million as of September 30, 2008. It will also lead to a loss of TCC's right to claim accelerated tax depreciation in future tax returns. If TCC is required to repay to the IRS its ADITC and is also required to refund ADITC to customers, it would have an unfavorable effect on future net income and cash flows. Tax counsel advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are actually returned to ratepayers under a nonappealable order. Management intends to continue to work with the PUCT to resolve the issue and avoid the adverse effects of a normalization violation on future net income, cash flows and financial condition.

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 in lieu of reducing stranded cost recoveries in the True-up Proceeding. It is possible that TCC's stranded cost recovery, which is currently on appeal, may be affected by a PUCT remedy.

In May 2008, the Texas Court of Appeals issued a decision in TCC's True-up Proceeding determining that even though excess earnings had been previously refunded to REPs, TCC still must reduce stranded cost recoveries in its 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 prior refunds to them by TCC. However, certain parties have taken positions that, if adopted, could result in TCC being required to refund additional amounts of excess earnings or interest through the true-up process without receiving a refund back from the REPs. If this were to occur it would have an adverse effect on future net income and cash flows. AEP sold its affiliate REPs in December 2002. While AEP owned the affiliate REPs, TCC refunded $11 million of excess earnings to the affiliate REPs. Management cannot predict the outcome of the excess earnings remand and whether it will adversely affect future net income and cash flows.

OTHER TEXAS RATE MATTERS

Hurricanes Dolly and Ike

In July and September 2008, TCC's service territory in south Texas was hit by Hurricanes Dolly and Ike, respectively. TCC incurred $11 million and $1 million in incremental operation and maintenance costs related to service restoration efforts for Hurricanes Dolly and Ike, respectively. TCC has a PUCT-approved catastrophe reserve which permits TCC to collect $1.3 million on an annual basis with authority to continue the collection until the catastrophe reserve reaches $13 million. Any incremental operation and maintenance costs can be charged against the catastrophe reserve if the total incremental operation and maintenance costs for a storm exceed $500 thousand. In June 2008, prior to these hurricanes, TCC had approximately $2 million recorded in the catastrophe reserve account. Since the catastrophe reserve balance was less than the incremental operation and maintenance costs related to Hurricanes Dolly and Ike, TCC established a net regulatory asset for $10 million.

Under Texas law and as previously approved by the PUCT in prior base rate cases, the regulatory asset will be included in rate base in the next base rate filing. At that time, TCC will evaluate the existing catastrophe reserve amounts and review potential future events to determine the appropriate funding level to request.

ETT

In December 2007, TCC contributed $70 million of transmission facilities to ETT. The PUCT approved ETT's initial rates, its request for a transfer of facilities and a certificate of convenience and necessity to operate as a stand alone transmission utility in the ERCOT region. ETT was awarded a 9.96% after tax return on equity rate in those approvals. In 2008, intervenors filed a notice of appeal to the Travis County District Court. In October 2008, 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 has complied with what the court determined was the proper section of the statute. As of September 30, 2008, AEP's net investment in ETT was $16 million. ETT is considering its options for responding to the ruling including an appeal of the Travis County District Court ruling. Depending upon the ultimate outcome of the Travis County District Court ruling, TCC may be required to reacquire transferred assets and projects under construction by ETT. Management cannot predict the outcome of this proceeding or its future effect on net income and cash flows.

Stall Unit

See "Stall Unit" section within the Louisiana Rate Matters for disclosure.

Turk Plant

See “Turk Plant” section within the Arkansas Rate Matters for disclosure.

Virginia Rate Matters

Virginia Base Rate Filing

In May 2008, APCo filed an application with the Virginia SCC to increase its base rates by $208 million on an annual basis. The requested increase is based upon a calendar 2007 test year adjusted for changes in revenues, expenses, rate base and capital structure through June 2008. This is consistent with the ratemaking treatment adopted by the Virginia SCC in APCo’s 2006 base rate case. The proposed revenue requirement reflects a return on equity of 11.75%. Hearings began in October 2008. As permitted under Virginia law, APCo implemented these new base rates, subject to refund, effective October 28, 2008.

In September 2008, the Attorney General’s office filed testimony recommending the proposed $208 million annual increase in base rate be reduced to $133 million. The decrease is principally due to the use of a return on equity approved in the last base rate case of 10% and various rate base and operating income adjustments, including a $25 million proposed disallowance of capacity equalization charges payable by APCo as a deficit member of the FERC approved AEP Power Pool.

In October 2008, the Virginia SCC staff filed testimony recommending the proposed $208 million annual increase in base rate be reduced to $157 million. The decrease is principally due to the use of a recommended return on equity of 10.1%. In October 2008, hearings were held in which APCo filed a $168 million settlement agreement which was accepted by all parties except one industrial customer. APCo expects to receive a final order from the Virginia SCC in November 2008.

Virginia E&R Costs Recovery Filing

As of September 2008, APCo has $118 million of deferred Virginia incremental E&R costs (excluding $25 million of unrecognized equity carrying costs). The $118 million consists of $6 million already approved by the Virginia SCC to be collected during the fourth quarter 2008, $54 million relating to APCo’s May 2008 filing for recovery in 2009, and $58 million, representing costs deferred in 2008 to date, to be included (along with the fourth quarter 2008 E&R deferrals) in the 2009 E&R filing, to be collected in 2010.

In September 2008, a settlement was reached between the parties to the 2008 filing and a stipulation agreement (stipulation) was submitted to the hearing examiner. The stipulation provides for recovery of $61 million of incremental E&R costs in 2009 which is an increase of $12 million over the level of E&R surcharge revenues being collected in 2008. The stipulation included an unfavorable $1 million adjustment related to certain costs considered not recoverable E&R costs and recovery of $4.5 million representing one-half of a $9 million Virginia jurisdictional portion of NSR settlement expenses recorded in 2007. In accordance with the stipulation, APCo will request the remaining one-half of the $9 million of NSR settlement expenses in APCo’s 2009 E&R filing. The stipulation also specifies that APCo will remove $3 million of the $9 million of NSR settlement expenses requested to be recovered over 3 years in the current base rate case from the base rate case’s revenue requirement.

In September 2008, the hearing examiner recommended that the Virginia SCC accept the stipulation. As a result, in September 2008, APCo deferred as a regulatory asset $9 million of NSR settlement expenses it had expensed in 2007 that have become probable of future recovery. In October 2008, the Virginia SCC approved the stipulation which will have a favorable effect on 2009 future cash flows of $61 million and on net income for the previously unrecognized equity costs of approximately $11 million. If the Virginia SCC were to disallow a material portion of APCo’s 2008 deferral, it would have an adverse effect on future net income and cash flows.

Virginia Fuel Clause Filings

In July 2007, APCo filed an application with the Virginia SCC to seek an annualized increase, effective September 1, 2007, of $33 million for fuel costs and sharing of off-system sales.

In February 2008, the Virginia SCC issued an order that approved a reduced fuel factor effective with the February 2008 billing cycle. The order terminated the off-system sales margin rider and approved a 75%-25% sharing of off-system sales margins between customers and APCo effective September 1, 2007 as required by the re-regulation legislation in Virginia. The order also allows APCo to include in its monthly under/over recovery deferrals the Virginia jurisdictional share of PJM transmission line loss costs from June 2007. The adjusted factor increases annual fuel clause revenues by $4 million. The order authorized the Virginia SCC staff and other parties to make specific recommendations to the Virginia SCC in APCo's next fuel factor proceeding to ensure accurate assignment of the prudently incurred PJM transmission line loss costs to APCo's Virginia jurisdictional operations. Management believes the incurred PJM transmission line loss costs are prudently incurred and are being properly assigned to APCo's Virginia jurisdictional operations.

In July 2008, APCo filed its next fuel factor proceeding with the Virginia SCC and requested an annualized increase of $132 million effective September 1, 2008. The increase primarily relates to increases in coal costs. In August 2008, the Virginia SCC issued an order to allow APCo to implement the increased fuel factor on an interim basis for services rendered after August 2008. In September 2008, the Virginia SCC staff filed testimony recommending a lower fuel factor which will result in an annualized increase of $117 million, which includes the PJM transmission line loss costs, instead of APCo's proposed $132 million. In October 2008, the Virginia SCC ordered an annualized increase of $117 million for services rendered on and after October 20, 2008.

APCo's Virginia SCC Filing for an IGCC Plant

In July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover initial costs associated with a proposed 629 MW IGCC plant to be constructed in Mason County, West Virginia adjacent to APCo's existing Mountaineer Generating Station for an estimated cost of $2.2 billion. The filing requested recovery of an estimated $45 million over twelve months beginning January 1, 2009 including a return on projected CWIP and development, design and planning pre-construction costs incurred from July 1, 2007 through December 31, 2009. APCo also requested authorization to defer a return on deferred pre-construction costs incurred beginning July 1, 2007 until such costs are recovered. Through September 30, 2008, APCo has deferred for future recovery pre-construction IGCC costs of approximately $9 million allocated to Virginia jurisdictional operations.

The Virginia SCC issued an order in April 2008 denying APCo's requests stating the belief that the estimated cost may be significantly understated. The Virginia SCC also expressed concern that the $2.2 billion estimated cost did not include a retrofitting of carbon capture and sequestration facilities. In April 2008, APCo filed a petition for reconsideration in Virginia. In May 2008, the Virginia SCC denied APCo's request to reconsider its previous ruling. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expense being incurred and certification of the IGCC plant prior to July 2010. Although management continues to pursue the construction of the IGCC plant, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

Mountaineer Carbon Capture Project

In January 2008, APCo and ALSTOM Power Inc. (Alstom), an unrelated third party, entered into an agreement to jointly construct a CO_2 capture facility. APCo and Alstom will each own part of the CO_2 capture facility. APCo will also construct and own the necessary facilities to store the CO_2. APCo's estimated cost for its share of the facilities is $76 million. Through September 30, 2008, APCo incurred $13 million in capitalized project costs which is included in Regulatory Assets. APCo plans to seek recovery for the CO_2 capture and storage project costs in its next Virginia and West Virginia base rate filings which are expected to be filed in 2009. APCo is presently seeking a return on the capitalized project costs in its current Virginia base rate filing. The Attorney General has recommended that the project costs should be shared by all affiliated operating companies with coal-fired generation plants. If a significant portion of the project costs are excluded from base rates and ultimately disallowed in Virginia and/or West Virginia, it could have an adverse effect on future net income and cash flows.

West Virginia Rate Matters

APCo's and WPCo's 2008 Expanded Net Energy Cost (ENEC) Filing

In February 2008, APCo and WPCo filed for an increase of approximately $156 million including a $135 million increase in the ENEC, a $17 million increase in construction cost surcharges and $4 million of reliability expenditures, to become effective July 2008. In June 2008, the WVPSC issued an order approving a joint stipulation and settlement agreement granting rate increases, effective July 2008, of approximately $106 million, including an $88 million increase in the ENEC, a $14 million increase in construction cost surcharges and $4 million of reliability expenditures. The ENEC is an expanded form of fuel clause mechanism, which includes all energy-related costs including fuel, purchased power expenses, off-system sales credits, PJM costs associated with transmission line losses due to the implementation of marginal loss pricing and other energy/transmission items.

The ENEC is subject to a true-up to actual costs and should have no earnings effect if actual costs exceed the recoveries due to the deferral of any over/under-recovery of ENEC costs. The construction cost and reliability surcharges are not subject to a true-up to actual costs and could impact future net income and cash flows.

APCo's West Virginia IGCC Plant Filing

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity (CCN) to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer Generating Station in Mason County, West Virginia.

In June 2007, APCo filed testimony with the WVPSC supporting the requests for a CCN and for pre-approval of a surcharge rate mechanism to provide for the timely recovery of both 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. In March 2008, the WVPSC granted APCo the CCN to build the plant and the request for cost recovery. Also, in March 2008, various intervenors filed petitions with the WVPSC to reconsider the order. No action has been taken on the requests for rehearing. At the time of the filing, the cost of the plant was estimated at $2.2 billion. As of September 30, 2008, the estimated cost of the plant has continued to significantly increase. In July 2008, based on the unfavorable order received in Virginia, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed. See the "APCo's Virginia SCC Filing for an IGCC Plant" section above. Through September 30, 2008, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to the West Virginia jurisdiction and approximately $2 million applicable to the FERC jurisdiction. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant. Although management continues to pursue the ultimate construction of the IGCC plant, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

Indiana Rate Matters

Indiana Base Rate Filing

In a January 2008, filing with the IURC, updated in the second quarter of 2008, I&M requested an increase in its Indiana base rates of $80 million including a return on equity of 11.5%. The base rate increase includes the $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. The depreciation reduction will no longer favorably impact earnings and will adversely affect cash flows when tariff rates are revised to reflect the effect of the depreciation expense reduction. The filing also requests trackers for certain variable components of the cost of service including recently increased PJM costs associated with transmission line losses due to the implementation of marginal loss pricing and other RTO costs, reliability enhancement costs, demand side management/energy efficiency costs, off-system sales margins and environmental compliance costs. The trackers would initially increase annual revenues by an additional $45 million. I&M proposes to share with ratepayers, through a tracker, 50% of off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million.

In September 2008, the Indiana Office of Utility Consumer Counselor (OUCC) and the Industrial Customer Coalition filed testimony recommending a $14 million and $37 million decrease in revenue, respectively. Two other intervenors filed testimony on limited issues. The OUCC and the Industrial Customer Coalition recommended that the IURC reduce the ROE proposed by I&M, reduce or limit the amount of off-system sales margin sharing, deny the recovery of reliability enhancement costs and reject the proposed environmental compliance cost recovery trackers. In October 2008, I&M filed testimony rebutting the recommendations of the OUCC. Hearings are scheduled for December 2008. A decision is expected from the IURC by June 2009.

Michigan Rate Matters

Michigan Restructuring

Although customer choice commenced for I&M's Michigan customers on January 1, 2002, I&M's rates for generation in Michigan continued to be cost-based regulated because none of I&M's customers elected to change suppliers and no alternative electric suppliers were registered to compete in I&M's Michigan service territory. In October 2008, the Governor of Michigan signed legislation to limit customer choice load to no more than 10% of the annual retail load for the preceding calendar year and to require the remaining 90% of annual retail load to be phased into cost-based rates. The new legislation also requires utilities to meet certain energy efficiency and renewable portfolio standards and requires cost recovery of meeting those standards. Management continues to conclude that I&M's rates for generation in Michigan are cost-based regulated.

Kentucky Rate Matters

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. Both the KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis these surcharges recently ranged from revenues of approximately $10 million to a reduction of revenues of $2 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The AG responded that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC issued an order stating that it has the authority to provide for surcharges and surcredits until the court of appeals rules. The appeals process could take up to two years to complete. The AG agreed to stay its challenge during that time.

We expect any adverse court of appeals decision could be applied prospectively but it is possible that a retrospective refund could also be ordered. KPCo's exposure is indeterminable at this time although an adverse decision would have an unfavorable effect on future net income and cash flows, assuming the legislature does not enact legislation that authorizes such surcharges.

2008 Fuel Cost Reconciliation

In January 2008, KPCo filed its semi-annual fuel cost reconciliation covering the period May 2007 through October 2007. As part of this filing, KPCo sought recovery of incremental costs associated with transmission line losses billed by PJM since June 2007 due to PJM's implementation of marginal loss pricing. KPCo expensed these incremental PJM costs associated with transmission line losses pending a determination that they are recoverable through the Kentucky fuel clause. In June 2008, the KPSC issued an order approving KPCo's semi-annual fuel cost reconciliation filing and recovery of incremental costs associated with transmission line losses billed by PJM. For the nine months ended September 30, 2008, KPCo recorded $16 million of income and the related Regulatory Asset for Under-Recovered Fuel Costs for transmission line losses incurred from June 2007 through September 2008 of which $7 million related to 2007.

Oklahoma Rate Matters

PSO Fuel and Purchased Power

The Oklahoma Industrial Energy Consumers appealed an ALJ recommendation in June 2008 regarding a pending fuel case involving the reallocation of $42 million of purchased power costs among AEP West companies in 2002. The Oklahoma Industrial Energy Consumers requested that PSO be required to refund this $42 million of reallocated purchased power costs through its fuel clause. PSO had recovered the $42 million during the period June 2007 through May 2008. In August 2008, the OCC heard the appeal and a decision is pending.

In February 2006, the OCC enacted a rule, requiring the OCC staff to conduct prudence reviews on PSO's generation and fuel procurement processes, practices and costs on a periodic basis. PSO filed testimony in June 2007 covering a prudence review for the year 2005. The OCC staff and intervenors filed testimony in September 2007, and hearings were held in November 2007. The only major issue in the proceeding was the alleged under allocation of off-system sales credits under the FERC-approved allocation methodology, which previously was determined not to be jurisdictional to the OCC. See "Allocation of Off-system Sales Margins" section within "FERC Rate Matters". Consistent with the prior OCC determination, the ALJ found that the OCC lacked authority to alter the FERC-approved allocation methodology and that PSO's fuel costs were prudent. The intervenors appealed the ALJ recommendation and the OCC heard the appeal in August 2008. In August 2008, the OCC filed a complaint at the FERC alleging that AEPSC inappropriately allocated off-system trading margins between the AEP East companies and the AEP West companies and did not properly allocate off-system trading margins within the AEP West companies.

In November 2007, PSO filed testimony in another proceeding to address its fuel costs for 2006. In April 2008, intervenor testimony was filed again challenging the allocation of off-system sales credits during the portion of the year when the allocation was in effect. Hearings were held in July 2008 and the OCC changed the scope of the proceeding from a prudence review to only a review of the mechanics of the fuel cost calculation. No party contested PSO's fuel cost calculation. In August 2008, the OCC issued a final order that PSO's calculations of fuel and purchased power costs were accurate and are consistent with PSO's fuel tariff.

In September 2008, the OCC initiated a review of PSO's generation, purchased power and fuel procurement processes and costs for 2007. Under the OCC minimum filing requirements, PSO is required to file testimony and supporting data within 60 days which will occur in the fourth quarter of 2008. Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings or prudence reviews. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and therefore are legally recoverable.

Red Rock Generating Facility

In July 2006, PSO announced an agreement with Oklahoma Gas and Electric Company (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit. PSO would own 50% of the new unit. Under the agreement, OG&E would manage construction of the plant. OG&E and PSO requested pre-approval to construct the coal-fired Red Rock Generating Facility (Red Rock) and to implement a recovery rider.

In October 2007, the OCC issued a final order approving PSO's need for 450 MWs of additional capacity by the year 2012, but rejected the ALJ's recommendation and denied PSO's and OG&E's applications for construction pre-approval. The OCC stated that PSO failed to fully study other alternatives to a coal-fired plant. Since PSO and OG&E could not obtain pre-approval to build Red Rock, PSO and OG&E cancelled the third party construction contract and their joint venture development contract. In June 2008, PSO issued a request-for-proposal to meet its capacity and energy needs.

In December 2007, PSO filed an application at the OCC requesting recovery of $21 million in pre-construction costs and contract cancellation fees associated with Red Rock. In March 2008, PSO and all other parties in this docket signed a settlement agreement that provides for recovery of $11 million of Red Rock costs, and provides carrying costs at PSO's AFUDC rate beginning in March 2008 and continuing until the $11 million is included in PSO's next base rate case. PSO will recover the costs over the expected life of the peaking facilities at the Southwestern Station, and include the costs in rate base in its next base rate filing. The settlement was filed with the OCC in March 2008. The OCC approved the settlement in May 2008. As a result of the settlement, PSO wrote off $10 million of its deferred pre-construction costs/cancellation fees in the first quarter of 2008. In July 2008, PSO filed a base rate case which included $11 million of deferred Red Rock costs plus carrying charges at PSO's AFUDC rate beginning in March 2008. See "2008 Oklahoma Base Rate Filing" section below.

Oklahoma 2007 Ice Storms

In October 2007, PSO filed with the OCC requesting recovery of $13 million of operation and maintenance expense related to service restoration efforts after a January 2007 ice storm. PSO proposed in its application to establish a regulatory asset of $13 million to defer the previously expensed January 2007 ice storm restoration costs and to amortize the regulatory asset coincident with gains from the sale of excess SO_2 emission allowances. In December 2007, PSO expensed approximately $70 million of additional storm restoration costs related to the December 2007 ice storm.

In February 2008, PSO entered into a settlement agreement for recovery of costs from both ice storms. In March 2008, the OCC approved the settlement subject to an audit of the final December ice storm costs filed in July 2008. As a result, PSO recorded an $81 million regulatory asset for ice storm maintenance expenses and related carrying costs less $9 million of amortization expense to offset recognition of deferred gains from sales of SO_2 emission allowances. Under the settlement agreement, PSO would apply proceeds from sales of excess SO_2 emission allowances of an estimated $26 million to recover part of the ice storm regulatory asset. The settlement also provided for PSO to amortize and recover the remaining amount of the regulatory asset through a rider over a period of five years beginning in the fourth quarter of 2008. The regulatory asset will earn a return of 10.92% on the unrecovered balance.

In June 2008, PSO adjusted its regulatory asset to true-up the estimated costs to actual costs. After the true-up, application of proceeds from to-date sales of excess SO_2 emission allowances and carrying costs, the ice storm regulatory asset was $64 million. The estimate of future gains from the sale of SO_2 emission allowances has significantly declined with the decrease in value of such allowances. As a result, estimated collections from customers through the special storm damage recovery rider will be higher than the estimate in the settlement agreement. In July 2008, as required by the settlement agreement, PSO filed its reconciliation of the December 2007 storm restoration costs along with a proposed tariff to recover the amounts not offset by the sales of SO_2 emission allowances. In September 2008, the OCC staff filed testimony supporting PSO's filing with minor changes. In October 2008, an ALJ recommended that PSO recover $62 million of the December 2007 storm restoration costs before consideration of emission allowance gains and carrying costs. In October 2008, the OCC approved the filing which allows PSO to recover $62 million of the December 2007 storm restoration costs beginning in November 2008.

2008 Oklahoma Annual Fuel Factor Filing

In May 2008, pursuant to its tariff, PSO filed its annual update with the OCC for increases in the various service level fuel factors based on estimated increases in fuel costs, primarily natural gas and purchased power expenses, of approximately $300 million. The request included recovery of $26 million in under-recovered deferred fuel. In June 2008, PSO implemented the fuel factor increase. Because of the substantial increase, the OCC held an administrative proceeding to determine whether the proposed charges were based upon the appropriate coal, purchased gas and purchased power prices and were properly computed. In June 2008, the OCC ordered that PSO properly estimated the increase in natural gas prices, properly determined its fuel costs and, thus, should implement the increase.

2008 Oklahoma Base Rate Filing

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million on an annual basis. PSO recovers costs related to new peaking units recently placed into service through the Generation Cost Recovery Rider (GCRR). Upon implementation of the new base rates, PSO will recover these costs through the new base rates and the GCRR will terminate. Therefore, PSO's net annual requested increase in total revenues is actually $117 million. The requested increase is based upon a test year ended February 29, 2008, adjusted for known and measurable changes through August 2008, which is consistent with the ratemaking treatment adopted by the OCC in PSO's 2006 base rate case. The proposed revenue requirement reflects a return on equity of 11.25%. PSO expects hearings to begin in December 2008 and new base rates to become effective in the first quarter of 2009. In October 2008, the OCC staff, the Attorney General's office, and a group of industrial customers filed testimony recommending annual base rate increases of $86 million, $68 million and $29 million, respectively. The differences are principally due to the use of recommended return on equity of 10.88%, 10% and 9.5% by the OCC staff, the Attorney General's office, and a group of industrial customers. The OCC staff and the Attorney General's office recommended $22 million and $8 million, respectively, of costs included in the filing be recovered through the fuel adjustment clause and riders outside of base rates.

Louisiana Rate Matters

Louisiana Compliance Filing

In connection with SWEPCo's merger related compliance filings, the LPSC approved a settlement agreement in April 2008 that prospectively resolves all issues regarding claims that SWEPCo had over-earned its allowed return. SWEPCo agreed to a formula rate plan (FRP) with a three-year term. Under the plan, beginning in August 2008, rates shall be established to allow SWEPCo to earn an adjusted return on common equity of 10.565%. The adjustments are standard Louisiana rate filing adjustments.

If in the second and third year of the FRP, the adjusted earned return is within the range of 10.015% to 11.115%, no adjustment to rates is necessary. However, if the adjusted earned return is outside of the above-specified range, an FRP rider will be established to increase or decrease rates prospectively. If the adjusted earned return is less than 10.015%, SWEPCo will prospectively increase rates to collect 60% of the difference between 10.565% and the adjusted earned return. Alternatively, if the adjusted earned return is more than 11.115%, SWEPCo will prospectively decrease rates by 60% of the difference between the adjusted earned return and 10.565%. SWEPCo will not record over/under recovery deferrals for refund or future recovery under this FRP.

The settlement provides for a separate credit rider decreasing Louisiana retail base rates by $5 million prospectively over the entire three-year term of the FRP, which shall not affect the adjusted earned return in the FRP calculation. This separate credit rider will cease effective August 2011.

In addition, the settlement provides for a reduction in generation depreciation rates effective October 2007. SWEPCo will defer as a regulatory liability, the effects of the expected depreciation reduction through July 2008. SWEPCo will amortize this regulatory liability over the three-year term of the FRP as a reduction to the cost of service used to determine the adjusted earned return. In August 2008, the LPSC issued an order approving the settlement.

In April 2008, SWEPCo filed the first FRP which would increase its annual Louisiana retail rates by $11 million in August 2008 to earn an adjusted return on common equity of 10.565%. In accordance with the settlement, SWEPCo recorded a $4 million regulatory liability related to the reduction in generation depreciation rates. The amount of the unamortized regulatory liability for the reduction in generation depreciation was $4 million as of September 30, 2008. In August 2008, SWEPCo implemented the FRP rates, subject to refund, as the LPSC staff reviews SWEPCo's FRP filing and the production depreciation study.

Stall Unit

In May 2006, SWEPCo announced plans to build a new intermediate load, 500 MW, natural gas-fired, combustion turbine, combined cycle generating unit (the Stall Unit) at its existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo submitted the appropriate filings to the PUCT, the APSC, the LPSC and the Louisiana Department of Environmental Quality to seek approvals to construct the unit. The Stall Unit is currently estimated to cost $378 million, excluding AFUDC, and is expected to be in-service in mid-2010.

In March 2007, the PUCT approved SWEPCo's request for a certificate for the facility based on a prior cost estimate. In September 2008, the LPSC approved SWEPCo's request for certification to construct the Stall Plant. The APSC has not established a procedural schedule at this time. The Louisiana Department of Environmental Quality issued an air permit for the unit in March 2008. If SWEPCo does not receive appropriate authorizations and permits to build the Stall Unit, SWEPCo would seek recovery of the capitalized pre-construction costs including any cancellation fees. As of September 30, 2008, SWEPCo has capitalized pre-construction costs of $158 million and has contractual construction commitments of an additional $145 million. As of September 30, 2008, if the plant had been cancelled, cancellation fees of $61 million would have been required in order to terminate these construction commitments. If SWEPCo cancels the plant and cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

Turk Plant

See "Turk Plant" section within Arkansas Rate Matters for disclosure.

<u>Arkansas Rate Matters</u>

Turk Plant

In August 2006, SWEPCo announced plans to build the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. Ultra-supercritical technology uses higher temperatures and higher pressures to produce electricity more efficiently thereby using less fuel and providing substantial emissions reductions. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking certification of the plant. SWEPCo will own 73% of the Turk Plant and will operate the facility. During 2007, SWEPCo signed joint ownership agreements with the Oklahoma Municipal Power Authority (OMPA), the Arkansas Electric Cooperative Corporation (AECC) and the East Texas Electric Cooperative (ETEC) for the remaining 27% of the Turk Plant. The Turk Plant is currently estimated to cost $1.5 billion, excluding AFUDC, with SWEPCo's portion estimated to cost $1.1 billion. If approved on a timely basis, the plant is expected to be in-service in 2012.

In November 2007, the APSC granted approval to build the plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant.

In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the $1.5 billion projected construction cost, excluding AFUDC, (b) capping CO_2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. An intervenor filed a motion for rehearing seeking reversal of the PUCT's decision. SWEPCo filed a motion for rehearing stating that the two cost cap restrictions are unlawful. In September 2008, the motions for rehearing were denied. In October 2008, SWEPCo appealed the PUCT's order regarding the two cost cap restrictions. If the cost cap restrictions are upheld and construction or emissions costs exceed the restrictions, it could have a material adverse impact on future net income and cash flows. In October 2008, an intervenor filed an appeal contending that the PUCT's grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

SWEPCo is also working with the Arkansas Department of Environmental Quality for the approval of an air permit and the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. Once SWEPCo receives the air permit, they will commence construction. A request to stop pre-construction activities at the site was filed in Federal court by the same Arkansas landowners who appealed the APSC decision to the Arkansas State Court of Appeals. In July 2008, the Federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In January 2008 and July 2008, SWEPCo filed applications for authority with the APSC to construct transmission lines necessary for service from the Turk Plant. Several landowners filed for intervention status and one landowner also contended he should be permitted to re-litigate Turk Plant issues, including the need for the generation. The APSC granted their intervention but denied the request to re-litigate the Turk Plant issues. The landowner filed an appeal to the Arkansas State Court of Appeals in June 2008.

The Arkansas Governor’s Commission on Global Warming is scheduled to issue its final report to the Governor by November 1, 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. If legislation is passed as a result of the findings in the Commission’s report, it could impact SWEPCo’s proposal to build the Turk Plant.

If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of September 30, 2008, SWEPCo has capitalized approximately $448 million of expenditures and has significant contractual construction commitments for an additional $771 million. As of September 30, 2008, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $61 million. If the Turk Plant does not receive all necessary approvals on reasonable terms and SWEPCo cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

Stall Unit

See “Stall Unit” section within Louisiana Rate Matters for disclosure.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at 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 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues.

In August 2006, a FERC 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 the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ’s initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, 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 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 disallowance of a large portion on any unsettled SECA revenues.

During 2006, based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $37 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. AEP has completed settlements totaling $7 million applicable to $75 million of SECA revenues. The balance in the reserve for future settlements as of September 2008 was $35 million. In-process settlements total $3 million applicable to $37 million of SECA revenues. Management believes that the available $32 million of reserves for possible refunds are sufficient to settle the remaining $108 million of contested SECA revenues.

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 will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the remaining reserve of $32 million is adequate to cover all remaining settlements. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if necessary.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them. AEP requested rehearing of this order, which the FERC denied. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 80% of the lost T&O transmission revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future net income and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 20% of the lost T&O transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. Should this effort be successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in additional annual revenues of approximately $9 million from nonaffiliated customers within PJM. The remaining $54 million requested would be billed to the AEP East companies to be recovered in retail rates. Retail rates for jurisdictions other than Ohio are not affected until the next base rate filing at FERC. Retail rates for CSPCo and OPCo would be adjusted through the Transmission Cost Recovery Rider (TCRR) totaling approximately $10 million and $12 million, respectively. The TCRR includes a true-up mechanism so CSPCo's and OPCo's net income will not be adversely affected by a FERC ordered transmission rate increase. Other jurisdictions would be recoverable on a lag basis as base rates are changed. AEP requested an effective date of October 1, 2008. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, suspended the effective date until March 1, 2009 and established a settlement proceeding with an ALJ. Management is unable to predict the outcome of this filing.

FERC Market Power Mitigation

The FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. Sellers with market rate authority must, at least every three years, update their studies demonstrating lack of market power. In December 2007, AEP filed its most recent triennial update. In March and May 2008, the PUCO filed comments suggesting that the FERC should further investigate whether AEP continues to pass the FERC's indicative screens for the lack of market power in PJM. Certain industrial retail customers also requested the FERC to further investigate this matter. AEP responded that its market power studies were performed in accordance with the FERC's guidelines and continue to demonstrate lack of market power. In September 2008, the FERC issued an order accepting AEP's market-based rates with minor changes and rejected the PUCO's and the industrial retail customers' suggestions to further investigate AEP's lack of market power.

In an unrelated matter, in May 2008, the FERC issued an order in response to a complaint from the state of Maryland's Public Service Commission to hold a future hearing to review the structure of the three pivotal market power supplier tests in PJM. In September 2008, PJM filed a report on the results of the PJM stakeholder process concerning the three pivotal supplier market power tests which recommended the FERC not make major revisions to the test because the test is not unjust or unreasonable.

The FERC's order will become final if no requests for rehearing are filed. If a request for rehearing is filed and ultimately results in a further investigation by the FERC which limits AEP's ability to sell power at market-based rates in PJM, it would result in an adverse effect on future off-system sales margins and cash flows.

Allocation of Off-system Sales Margins

In 2004, intervenors and the OCC staff argued that AEP had inappropriately under-allocated off-system sales credits to PSO by $37 million for the period June 2000 to December 2004 under a FERC-approved allocation agreement. An ALJ assigned to hear intervenor claims found that the OCC lacked authority to examine whether AEP deviated from the FERC-approved allocation methodology for off-system sales margins and held that any such complaints should be addressed at the FERC. In October 2007, the OCC adopted the ALJ's recommendation and orally directed the OCC staff to explore filing a complaint at the FERC alleging the allocation of off-system sales margins to PSO is not in compliance with the FERC-approved methodology which could result in an adverse effect on future net income and cash flows for AEP Consolidated, the AEP East companies and the AEP West companies. In June 2008, the ALJ issued a final recommendation and incorporated the prior finding that the OCC lacked authority to review AEP's application of a FERC-approved methodology. In June 2008, the Oklahoma Industrial Energy Consumers appealed the ALJ recommendation to the OCC. In August 2008, the OCC heard the appeal and a decision is pending. See "PSO Fuel and Purchased Power" section within "Oklahoma Rate Matters". In August 2008, the OCC filed a complaint at the FERC alleging that AEPSC inappropriately allocated off-system trading margins between the AEP East companies and the AEP West companies and did not properly allocate off-system trading margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers have all intervened in this filing.

TCC, TNC and the PUCT have been involved in litigation in the federal courts concerning whether the PUCT has the right to order a reallocation of off-system sales margins thereby reducing recoverable fuel costs in the final fuel reconciliation in Texas under the restructuring legislation. In 2005, TCC and TNC recorded provisions for refunds after the PUCT ordered such reallocation. After receipt of favorable federal court decisions and the refusal of the U.S. Supreme Court to hear a PUCT appeal of the TNC decision, TCC and TNC reversed their provisions of $16 million and $9 million, respectively, in the third quarter of 2007.

Management cannot predict the outcome of these proceedings. However, management believes its allocations were in accordance with the then-existing FERC-approved allocation agreements and additional off-system sales margins should not be retroactively reallocated. The results of these proceedings could have an adverse effect on future net income and cash flows for AEP Consolidated, the AEP East companies and the AEP West companies.

4. 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. The Commitments, Guarantees and Contingencies note within our 2007 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters Of Credit

We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits 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 September 30, 2008, the maximum future payments for LOCs issued under the two $1.5 billion credit facilities are $67 million with maturities ranging from October 2008 to October 2009. The two $1.5 billion credit facilities were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $46 million following its bankruptcy.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. As of September 30, 2008, $372 million of letters of credit were issued by subsidiaries under the 3-year credit agreement to support variable rate demand notes.

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), an entity consolidated under FIN 46R. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of September 30, 2008, SWEPCo has collected approximately $37 million through a rider for final mine closure costs, of which approximately $7 million is recorded in Other Current Liabilities, $5 million is recorded in Asset Retirement Obligations and $25 million is recorded in Deferred Credits and Other on our Condensed Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all its costs. SWEPCo passes these costs 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 2007 Annual Report, "Dispositions" section of Note 8. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $1.3 billion (approximately $1 billion relates to the Bank of America (BOA) litigation, see "Enron Bankruptcy" section of this note). There are no material liabilities recorded for any indemnifications other than amounts recorded related to the BOA litigation.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. At September 30, 2008, the maximum potential loss for these lease agreements was approximately $66 million ($43 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

Railcar Lease

In June 2003, 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. We intend to maintain the lease for twenty years, via renewal options. 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 over the current lease term from approximately 84% to 77% of the projected fair market value of the equipment.

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 future minimum lease obligation is $20 million for I&M and $23 million for SWEPCo as of September 30, 2008. I&M and SWEPCo intend to renew these leases for the full remaining terms and have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee discussed above is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $14 million ($9 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current 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.

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. The alleged modifications occurred over a 20-year period. 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.

The AEP System settled their cases 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 SCR and flue gas desulfurization equipment (FGD or scrubbers) 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 in May 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in federal district court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. In April 2008, the parties filed a proposed consent decree to resolve all claims in this case and in the pending appeal of the altered permit for the Welsh Plant. The consent decree requires 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. The consent decree was entered as a final order in June 2008.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant. In April 2005, TCEQ issued an Executive Director's Report (Report) recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo. In 2008, the matter was remanded to TCEQ to pursue settlement discussions. The original Report contained a recommendation to limit the heat input on each Welsh unit to the referenced heat input contained within the state permit within 10 days of the issuance of a final TCEQ order and until the permit is changed. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit and to clarify the sulfur content requirement for fuels consumed at the plant. A permit alteration was issued in March 2007. In June 2007, TCEQ denied a motion to overturn the permit alteration. The permit alteration was appealed to the Travis County District Court, but was resolved by entry of the consent decree in the federal citizen suit action, and dismissed with prejudice in July 2008. Notice of an administrative settlement of the TCEQ enforcement action was published in June 2008. The settlement requires SWEPCo to pay an administrative penalty of $49 thousand and to fund a supplemental environmental project in the amount of $49 thousand, and resolves all violations alleged by TCEQ. In October 2008, TCEQ approved the settlement.

In February 2008, 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. SWEPCo met with the Federal EPA to discuss the alleged violations in March 2008. 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 (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the U.S. Supreme Court's decision on this case. We believe the actions are without merit and intend to defend against the claims.

Alaskan Villages' Claims

In February 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 & 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. The defendants filed motions to dismiss the action. The motions are pending before the court. We believe the action is without merit and intend to defend against the claims.

Clean Air Act Interstate Rule

In 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR), that required further reductions in SO_2 and NO_x emissions and assists states developing new state implementation plans to meet 1997 national ambient air quality standards (NAAQS). CAIR reduces regional emissions of SO_2 and NO_x (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals issued a decision that would vacate the CAIR and remand the rule to the Federal EPA. In September 2008, the Federal EPA and other parties petitioned for rehearing. We are unable to predict the outcome of the rehearing petitions or how the Federal EPA will respond to the remand which could be stayed or appealed to the U.S. Supreme Court.

In anticipation of compliance with CAIR in 2009, I&M purchased $9 million of annual CAIR NO_x allowances which are included in Deferred Charges and Other on our Condensed Consolidated Balance Sheet as of September 30, 2008. The market value of annual CAIR NO_x allowances decreased following this court decision. However, our weighted-average cost of these allowances is below market. If CAIR remains vacated, management intends to seek partial recovery of the cost of purchased allowances. Any unrecovered portion would have an adverse effect on future net income and cash flows. None of AEP's other subsidiaries purchased any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to our facilities under the Acid Rain Program and the NO_x state implementation plan (SIP) Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

It is too early to determine the full implication of these decisions on environmental compliance strategy. However, independent obligations under the CAA, including obligations under future state implementation plan submittals, and actions taken pursuant to the settlement of the NSR enforcement action, are consistent with the actions included in a least-cost CAIR compliance plan. Consequently, management does not anticipate making any immediate changes in near-term compliance plans as a result of these court decisions.

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

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

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. 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 take voluntary action necessary to prevent and/or mitigate public harm. I&M requested remediation proposals from environmental consulting firms. In May 2008, I&M issued a contract to one of the consulting firms. I&M recorded approximately $4 million of expense through September 30, 2008. As the remediation work is completed, I&M's cost may increase. I&M cannot predict the amount of additional cost, if any. At present, our estimates do not anticipate material cleanup costs for this site.

Cook Plant Unit 1 Fire and Shutdown

Cook Plant Unit 1 (Unit 1) is a 1,030 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations likely caused by blade failure which resulted in a fire on the electric generator. This equipment is in the turbine building and is separate and isolated from the nuclear reactor. The steam turbines that caused the vibration were installed in 2006 and are under warranty from the vendor. The warranty provides for the replacement of the turbines if the damage was caused by a defect in the design or assembly of the turbines. I&M is also working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and turbine vendor to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. We cannot estimate the ultimate costs of the outage at this time. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Our preliminary analysis indicates that Unit 1 could resume operations as early as late first quarter/early second quarter of 2009 or as late as the second half of 2009, depending upon whether the damaged components can be repaired or whether they need to be replaced.

I&M maintains property insurance through NEIL with a $1 million deductible. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12 week deductible period, I&M is entitled to weekly payments of $3.5 million during the outage period for a covered loss. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

TEM Litigation

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

In 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We alleged that TEM breached the PPA and sought a determination of our rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of our breaches.

In January 2008, we reached a settlement with TEM to resolve all litigation regarding the PPA. TEM paid us $255 million. We recorded the $255 million as a pretax gain in January 2008 under Asset Impairments and Other Related Charges on our Condensed Consolidated Statements of Income. This settlement and the PPA related to the Plaquemine Cogeneration Facility which was impaired and sold in 2006.

Enron Bankruptcy

In 2001, we purchased 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 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 misrepresentations and engaged in fraud to induce and promote the stock sale of

HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the 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 April 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 the four counts alleging breach of contract, fraud and negligent misrepresentation in the Southern District of Texas. HPL and BOA filed motions for summary judgment in the case pending in the Southern District of New York. Trial in federal court in Texas was continued pending a decision on the motions for summary judgment in the New York case.

In August 2007, the judge in the New York action issued a decision granting BOA summary judgment and dismissing our claims. In December 2007, the judge held that BOA is entitled to recover damages of approximately $347 million ($427 million including interest at December 31, 2007). In August 2008, the court entered a final judgment of $346 million (the original judgment less $1 million BOA would have incurred to remove 55 BCF of natural gas from the Bammel storage facility) and clarified the interest calculation method. We appealed and posted a bond covering the amount of the judgment entered against us.

In 2005, we sold our interest in HPL. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. After recalculation for the final judgment, the liability for the BOA litigation was $431 million at September 30, 2008. The liability for the BOA litigation was $427 million at December 31, 2007. These liabilities are included in Deferred Credits and Other on our Condensed Consolidated Balance Sheets.

Shareholder Lawsuits

In 2002 and 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions were pending in Federal District Court, Columbus, Ohio. In these actions, the plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. Two of the three actions were dropped voluntarily by the plaintiffs in those cases. In July 2006, the court entered judgment in the remaining case, denying plaintiff's motion for class certification and dismissing all claims without prejudice. In August 2007, the appeals court reversed the trial court's decision and held that the plaintiff did have standing to pursue his claim. The appeals court remanded the case to the trial court to consider the issue of whether the plaintiff is an adequate representative for the class of plan participants. In September 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 October 2008, Counsel for the plaintiff filed a motion to intervene on behalf of an individual seeking to intervene as a new plaintiff. We intend to oppose this motion and continue to defend against these claims.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against 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 June 2008, we settled all of the cases pending against us in California state court along with all of the cases brought against us in federal court by plaintiffs 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 remaining provision balance 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 in United States District Court, Western District of Oklahoma against AEP alleging breach of contract and breach of fiduciary duties related to negotiations for rail transportation services for the plant. The plaintiffs allege that AEP took the duty of the project manager, PSO, and operated the plant for the project manager and is therefore responsible for the alleged breaches. We intend to vigorously defend against these allegations.

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 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. Management is unable to predict the outcome of these proceedings or their impact on future net income and cash flows. We asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities.

5. ACQUISITIONS, DISPOSITIONS AND DISCONTINUED OPERATIONS

ACQUISITIONS

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 (PSEG) for $325 million and the assumption of liabilities of $3 million. AEGCo completed the purchase in May 2007. The Lawrenceburg plant is located in Lawrenceburg, Indiana, adjacent to I&M's Tanners Creek Plant, and is a natural gas, combined cycle power plant with a generating capacity of 1,096 MW. 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. As of September 30, 2008, AEGCo has incurred approximately $53 million in construction costs (excluding AFUDC) at the Dresden Plant and expects to incur approximately $169 million in additional costs (excluding AFUDC) prior to completion in 2010. The projected completion date of the Dresden Plant is currently under review. To the extent that the completion of the Dresden Plant is delayed, the total projected cost of the Dresden Plant could change. 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

2008

None

2007

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 working capital adjustments. The sale did not have an impact on our net income nor do we expect any remaining litigation to have a significant effect on our net income.

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

In March 2007, we sold 130,000 shares of ICE and recognized a $16 million pretax gain ($10 million, net of tax). We recorded the gain in Interest and Investment Income on our 2007 Condensed Consolidated Statement of Income. Our remaining investment of approximately 138,000 shares at September 30, 2008 and December 31, 2007 is recorded in Other Temporary Investments on our Condensed Consolidated Balance Sheets.

Texas REPs (Utility Operations segment)

As part of the purchase-and-sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings with Centrica from the two REPs above a threshold amount through 2006 if the Texas retail market developed increased earnings opportunities. In 2007, we received the final earnings sharing payment of $20 million. This payment is reflected in Gain on Disposition of Assets, Net on our Condensed Consolidated Statement of Income.

Sweeny Cogeneration Plant (Generation and Marketing segment)

In October 2007, we sold our 50% equity interest in the Sweeny Cogeneration Plant (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 pretax gain ($30 million, net of tax) in the fourth quarter of 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 pretax gain ($7 million, net of tax) in the fourth quarter of 2007, which is included in Other revenues on our 2007 Consolidated Statement of Income. In the fourth quarter of 2007, we recognized a total of $58 million in pretax gains ($37 million, net of tax).

DISCONTINUED OPERATIONS

We determined that certain of our operations were discontinued operations and classified them as such for all periods presented. We recorded the following in 2008 and 2007 related to discontinued operations:

Three Months Ended September 30,	U.K. Generation (a) (in millions)
2008 Revenue	$ -
2008 Pretax Income	-
2008 Earnings, Net of Tax	-
2007 Revenue	$ -
2007 Pretax Income	-
2007 Earnings, Net of Tax	-

Nine Months Ended September 30,	U.K. Generation (a) (in millions)
2008 Revenue	$ -
2008 Pretax Income	2
2008 Earnings, Net of Tax	1
2007 Revenue	$ -
2007 Pretax Income	3
2007 Earnings, Net of Tax	2

(a) The 2008 amounts relate to final proceeds received for the sale of land related to the sale of U.K. Generation. The 2007 amounts relate to tax adjustments from the sale of U.K. Generation.

There were no cash flows used for or provided by operating, investing or financing activities related to our discontinued operations for the nine months ended September 30, 2008 and 2007.

6. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following tables provide the components of our net periodic benefit cost for the plans for the three and nine months ended September 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 25	$ 24	$ 10	$ 11
Interest Cost	62	59	28	26
Expected Return on Plan Assets	(84)	(85)	(27)	(26)
Amortization of Transition Obligation	-	-	7	6
Amortization of Net Actuarial Loss	10	15	3	3
Net Periodic Benefit Cost	$ 13	$ 13	$ 21	$ 20

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 75	$ 72	$ 31	$ 32
Interest Cost	187	176	84	78
Expected Return on Plan Assets	(252)	(254)	(83)	(78)
Amortization of Transition Obligation	-	-	21	20
Amortization of Net Actuarial Loss	29	44	8	9
Net Periodic Benefit Cost	$ 39	$ 38	$ 61	$ 61

We have significant investments in several trust funds to provide for future pension and OPEB payments. All of our trust funds' investments are well-diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts has declined due to the decreases in the equity and fixed income markets. Although the asset values are currently lower, this decline has not affected the funds' ability to make their required payments.

7. BUSINESS SEGMENTS

As outlined in our 2007 Annual Report, our primary business strategy and the core of our business are to focus on 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. Generation/supply in Ohio continues to have commission-determined rates transitioning from cost-based to market-based rates. The legislature in Ohio is currently considering possibly returning to some form of cost-based rate-regulation or a hybrid form of rate-regulation for generation. 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 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

- Barging operations that annually transport approximately 35 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 39% of the barging is for transportation of agricultural products, 30% for coal, 14% for steel and 17% for other commodities. Effective July 30, 2008, AEP MEMCO LLC's name was changed to AEP River Operations LLC.

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.
- 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 liquidate and completely expire in 2011.
- The first quarter 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

The tables below present our reportable segment information for the three and nine months ended September 30, 2008 and 2007 and balance sheet information as of September 30, 2008 and December 31, 2007. These amounts include certain estimates and allocations where necessary. We reclassified prior year amounts to conform to the current year's segment presentation. See "FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)" section of Note 2 for discussion of changes in netting certain balance sheet amounts.

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended September 30, 2008						
Revenues from:						
External Customers	$ 4,108 (d)	$ 160	$ 1	$ (78)	$ -	$ 4,191
Other Operating Segments	(140)(d)	7	95	83	(45)	-
Total Revenues	$ 3,968	$ 167	$ 96	$ 5	$ (45)	$ 4,191
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 357	$ 11	$ 16	$ (10)	$ -	$ 374
Discontinued Operations, Net of Tax	-	-	-	-	-	-
Net Income (Loss)	$ 357	$ 11	$ 16	$ (10)	$ -	$ 374

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended September 30, 2007						
Revenues from:						
External Customers	$ 3,423(d)	$ 134	$ 241	$ (9)	$ -	$ 3,789
Other Operating Segments	177(d)	4	(161)	19	(39)	-
Total Revenues	$ 3,600	$ 138	$ 80	$ 10	$ (39)	$ 3,789
Net Income (Loss)	$ 388	$ 18	$ 3	$ (2)	$ -	$ 407

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Nine Months Ended September 30, 2008						
Revenues from:						
External Customers	$ 10,318(d)	$ 442	$ 409	$ 35	$ -	$ 11,204
Other Operating Segments	257(d)	18	(143)	(17)	(115)	-
Total Revenues	$ 10,575	$ 460	$ 266	$ 18	$ (115)	$ 11,204
Income Before Discontinued Operations and Extraordinary Loss	$ 1,030	$ 21	$ 43	$ 133	$ -	$ 1,227
Discontinued Operations, Net of Tax	-	-	-	1	-	1
Net Income	$ 1,030	$ 21	$ 43	$ 134	$ -	$ 1,228

Nine Months Ended September 30, 2007		Utility Operations	AEP River Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling Adjustments		Consolidated
				(in millions)				
Revenues from:								
External Customers	$	9,127(d)	$ 367	$ 574	$ 36	$ -	$	10,104
Other Operating Segments		460(d)	10	(347)	(14)	(109)		-
Total Revenues	$	9,587	$ 377	$ 227	22	(109)	$	10,104
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$	879	$ 40	$ 17	$ (1)	$ -	$	935
Discontinued Operations, Net of Tax		-	-	-	2	-		2
Extraordinary Loss, Net of Tax		(79)	-	-	-	-		(79)
Net Income	$	800	$ 40	$ 17	$ 1	$ -	$	858

September 30, 2008		Utility Operations	AEP River Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling Adjustments (c)		Consolidated
				(in millions)				
Total Property, Plant and Equipment	$	47,699	$ 316	$ 577	$ 45	$ (245)	$	48,392
Accumulated Depreciation and Amortization		16,413	69	133	8	(20)		16,603
Total Property, Plant and Equipment – Net	$	31,286	$ 247	$ 444	$ 37	$ (225)	$	31,789
Total Assets	$	41,322	$ 380	$ 771	$ 13,905	$ (13,340)(b)	$	43,038

December 31, 2007		Utility Operations	AEP River Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling Adjustments (c)		Consolidated
				(in millions)				
Total Property, Plant and Equipment	$	45,514	$ 263	$ 567	$ 38	$ (237)	$	46,145
Accumulated Depreciation and Amortization		16,107	61	112	7	(12)		16,275
Total Property, Plant and Equipment – Net	$	29,407	$ 202	$ 455	$ 31	$ (225)	$	29,870
Total Assets	$	39,298	$ 340	$ 697	$ 12,117	$ (12,133)(b)	$	40,319

(a) All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- 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 liquidate and completely expire in 2011.
- The first quarter 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. The cash settlement of $255 million ($163 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

(b) 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.

(c) Includes eliminations due to an intercompany capital lease.

(d) 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 to AEPEP in Revenues from Other Operating Segments of $(95) million and $161 million for the three months ended September 30, 2008 and 2007, respectively, and $143 million and $347 million for the nine months ended September 30, 2008 and 2007, respectively. The Generation and Marketing segment also reports these purchase or sales contracts with Utility Operations as Revenues from Other Operating Segments.

8. INCOME TAXES

We adopted FIN 48 as of January 1, 2007. As a result, we recognized an increase in liabilities for unrecognized tax benefits, as well as related interest and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings.

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 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 2000. However, we have filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. We have completed the exam for the years 2001 through 2003 and have issues that we are pursuing at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion adequate provisions for income taxes have been made for potential liabilities resulting from such matters. 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 does not believe that the ultimate resolution of these audits will 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.

Federal Tax Legislation

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of a new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. We announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. We filed applications for the West Virginia and Ohio IGCC projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was allocated credits during the first round of credit awards. After one of the original credit recipients surrendered their credits in the Fall of 2007, the IRS announced a supplemental credit round for the Spring of 2008. We filed a new application 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.

In October 2008, the Emergency Economic Stabilization Act of 2008 (the Act) was signed into law. The Act extended several expiring tax provisions and added new energy incentive provisions. The legislation impacted the availability of research credits, accelerated depreciation of smart meters, production tax credits and energy efficient commercial building deductions. 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.

State Tax Legislation

In March 2008, the Governor of West Virginia signed legislation 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.

9. FINANCING ACTIVITIES

Long-term Debt

Type of Debt	September 30, 2008	December 31, 2007
	(in millions)	
Senior Unsecured Notes	$ 11,186	$ 9,905
Pollution Control Bonds	1,817	2,190
First Mortgage Bonds	-	19
Notes Payable	244	311
Securitization Bonds	2,132	2,257
Junior Subordinated Debentures	315	-
Notes Payable To Trust	113	113
Spent Nuclear Fuel Obligation (a)	264	259
Other Long-term Debt	2	2
Unamortized Discount (net)	(66)	(62)
Total Long-term Debt Outstanding	16,007	14,994
Less Portion Due Within One Year	682	792
Long-term Portion	$ 15,325	$ 14,202

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation of $297 million and $285 million at September 30, 2008 and December 31, 2007, respectively, are included in Spent Nuclear Fuel and Decommissioning Trusts on our Condensed Consolidated Balance Sheets.

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2008 are shown in the tables below.

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	
Issuances:				
AEP	Junior Subordinated Debentures	$ 315	8.75	2063
APCo	Pollution Control Bonds	40	4.85	2019
APCo	Pollution Control Bonds	30	4.85	2019
APCo	Pollution Control Bonds	75	Variable	2036
APCo	Pollution Control Bonds	50	Variable	2036
APCo	Senior Unsecured Notes	500	7.00	2038
CSPCo	Senior Unsecured Notes	350	6.05	2018
I&M	Pollution Control Bonds	25	Variable	2019
I&M	Pollution Control Bonds	52	Variable	2021
I&M	Pollution Control Bonds	40	5.25	2025
OPCo	Pollution Control Bonds	50	Variable	2014
OPCo	Pollution Control Bonds	50	Variable	2014
OPCo	Pollution Control Bonds	65	Variable	2036
OPCo	Senior Unsecured Notes	250	5.75	2013
SWEPCo	Pollution Control Bonds	41	4.50	2011
SWEPCo	Senior Unsecured Notes	400	6.45	2019
Non-Registrant:				
TCC	Pollution Control Bonds	41	5.625	2017
TCC	Pollution Control Bonds	120	5.125	2030
TNC	Senior Unsecured Notes	30	5.89	2018
TNC	Senior Unsecured Notes	70	6.76	2038
Total Issuances		$ 2,594(a)		

Other than the possible dividend restrictions of the AEP Junior Subordinated Debentures, the above borrowing arrangements do not contain guarantees, collateral or dividend restrictions.

(a) Amount indicated on statement of cash flows of $2,561 million is net of issuance costs and premium or discount.

The net proceeds from the sale of Junior Subordinated Debentures were used for general corporate purposes including the payment of short-term indebtedness.

Company	Type of Debt	Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Senior Unsecured Notes	$ 200	3.60	2008
APCo	Pollution Control Bonds	40	Variable	2019
APCo	Pollution Control Bonds	30	Variable	2019
APCo	Pollution Control Bonds	18	Variable	2021
APCo	Pollution Control Bonds	50	Variable	2036
APCo	Pollution Control Bonds	75	Variable	2037
CSPCo	Senior Unsecured Notes	60	6.55	2008
CSPCo	Senior Unsecured Notes	52	6.51	2008
CSPCo	Pollution Control Bonds	48	Variable	2038
CSPCo	Pollution Control Bonds	44	Variable	2038
I&M	Pollution Control Bonds	45	Variable	2009
I&M	Pollution Control Bonds	25	Variable	2019
I&M	Pollution Control Bonds	52	Variable	2021
I&M	Pollution Control Bonds	50	Variable	2025
I&M	Pollution Control Bonds	50	Variable	2025
I&M	Pollution Control Bonds	40	Variable	2025
OPCo	Notes Payable	1	6.81	2008
OPCo	Notes Payable	12	6.27	2009
OPCo	Pollution Control Bonds	50	Variable	2014
OPCo	Pollution Control Bonds	50	Variable	2016
OPCo	Pollution Control Bonds	50	Variable	2022
OPCo	Pollution Control Bonds	35	Variable	2022
OPCo	Pollution Control Bonds	65	Variable	2036
PSO	Pollution Control Bonds	34	Variable	2014
SWEPCo	Pollution Control Bonds	41	Variable	2011
SWEPCo	Notes Payable	2	Variable	2008
SWEPCo	Notes Payable	3	4.47	2011
Non-Registrant:				
AEP Subsidiaries	Notes Payable	4	5.88	2011
AEP Subsidiaries	Notes Payable	10	Variable	2017
AEGCo	Senior Unsecured Notes	7	6.33	2037
AEPSC	Notes Payable	34	9.60	2008
TCC	First Mortgage Bonds	19	7.125	2008
TCC	Securitization Bonds	29	5.01	2008
TCC	Securitization Bonds	21	5.56	2010
TCC	Securitization Bonds	75	4.98	2010
TCC	Pollution Control Bonds	41	Variable	2015
TCC	Pollution Control Bonds	60	Variable	2028
TCC	Pollution Control Bonds	60	Variable	2028
Total Retirements and Principal Payments		$ 1,582		

In October 2008, SWEPCo retired $113 million of 5.25% Notes Payable due in 2043.

As of September 30, 2008, we had $272 million outstanding of tax-exempt long-term debt sold at auction rates (rates range between 4.353% and 13%) that reset every 35 days. Approximately $218 million of this debt relates to a lease structure with JMG that we are unable to refinance at this time. In order to refinance this debt, we need the lessor's consent. This debt is insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation and Financial Guaranty Insurance Co. Due to the exposure that these bond insurers had in connection with developments in the subprime credit market, the credit ratings of these insurers were downgraded or placed on negative outlook. These market factors contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions, including many of the auctions of our tax-exempt long-term debt. Consequently, we chose to exit the auction-rate debt market. 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. Through September 30, 2008, we reduced our outstanding auction rate securities by $1.2 billion. We plan to continue the conversion and refunding process for the remaining $272 million to other permitted modes, including term-put structures, variable-rate and fixed-rate structures, as opportunities arise.

As of September 30, 2008, $367 million of the prior auction rate debt was issued in a weekly variable rate mode supported by letters of credit at variable rates ranging from 6.5% to 8.25% and $495 million was issued at fixed rates ranging from 4.5% to 5.625%. As of September 30, 2008, trustees held, on our behalf, approximately $330 million of our reacquired auction rate tax-exempt long-term debt which we plan to reissue to the public as market conditions permit.

Dividend Restrictions

We have the option to defer interest payments on the AEP Junior Subordinated Debentures issued in March 2008 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 net income, cash flows, financial condition or limit any dividend payments in the foreseeable future.

Short-term Debt

Our outstanding short-term debt is as follows:

	September 30, 2008		December 31, 2007	
Type of Debt	**Outstanding Amount (in thousands)**	**Interest Rate**	**Outstanding Amount (in thousands)**	**Interest Rate**
Commercial Paper – AEP	$ 701,416	3.25% (a)	$ 659,135	5.54% (a)
Commercial Paper – JMG (b)	-	-	701	5.35% (a)
Line of Credit – Sabine Mining Company (c)	9,520	7.75% (a)	285	5.25% (a)
Line of Credit – AEP (e)	590,700	3.4813% (d)	-	-
Total	$ 1,301,636		$ 660,121	

(a) Weighted average rate.
(b) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility. This commercial paper does not reduce available liquidity under AEP's credit facilities.
(c) Sabine Mining Company is consolidated under FIN 46R. This line of credit does not reduce available liquidity under AEP's credit facilities.
(d) Rate based on 1-month LIBOR. In October 2008, this rate was converted to 4.55% based on prime.
(e) In October 2008, we borrowed an additional $1.4 billion at 4.55% based on prime.

Credit Facilities

As of September 30, 2008, in support of our commercial paper program, we had two $1.5 billion credit facilities which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $46 million following its bankruptcy. In March 2008, the credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, we may issue letters of credit. As of September 30, 2008, $372 million of letters of credit were issued by subsidiaries under the 3-year credit agreement to support variable rate demand notes.

Sale of Receivables – AEP Credit

In October 2008, we renewed AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of $600 million from bank conduits to purchase receivables from AEP Credit. This agreement will expire in October 2009.

APPALACHIAN POWER COMPANY

AND SUBSIDIARIES

Results of Operations

Third Quarter of 2008 Compared to Third Quarter of 2007

Reconciliation of Third Quarter of 2007 to Third Quarter of 2008
Income Before Extraordinary Loss
(in millions)

Third Quarter of 2007		$	24
Changes in Gross Margin:			
Retail Margins	(9)		
Off-system Sales	8		
Other	1		
Total Change in Gross Margin			-
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	26		
Depreciation and Amortization	(10)		
Taxes Other Than Income Taxes	(1)		
Carrying Costs Income	3		
Other Income	2		
Interest Expense	(2)		
Total Change in Operating Expenses and Other			18
Income Tax Expense			(3)
Third Quarter of 2008		$	39

Income Before Extraordinary Loss increased $15 million to $39 million in 2008 primarily due to a decrease in Operating Expenses and Other of $18 million, partially offset by an increase in Income Tax Expense of $3 million.

The major components of the change 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 decreased $9 million primarily due to an increase in sharing of off-system sales margins with customers and higher capacity settlement expenses under the Interconnection Agreement. These unfavorable effects were partially offset by the impact of the Virginia base rate order issued in May 2007 which included a 2007 provision for revenue refund in addition to an increase in the recovery of E&R costs in Virginia.
- Margins from Off-system Sales increased $8 million primarily due to increased physical sales margins driven by higher prices, partially offset by lower trading margins.

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

- Other Operation and Maintenance expenses decreased $26 million primarily due to the following:
  - A $26 million decrease resulting from a settlement agreement in the third quarter 2007 related to alleged violations of the NSR provisions of the CAA. The $26 million represents APCo's allocation of the settlement.
  - A $9 million decrease related to the establishment of a regulatory asset in the third quarter 2008 for Virginia's share of previously expended NSR settlement costs. See "Virginia E&R Cost Recovery Filing" section of Note 3.

  These decreases were partially offset by:
  - A $6 million increase in employee-related expenses.
  - A $5 million increase in overhead line maintenance expense primarily due to right-of-way clearing.
- Depreciation and Amortization expenses increased $10 million primarily due to a $6 million increase in the amortization of carrying charges and depreciation expense that are being collected through the Virginia E&R surcharges and a $3 million increase in depreciation expense primarily from the installation of environmental upgrades at the Mountaineer Plant.
- Carrying Costs Income increased $3 million due to an increase in Virginia E&R deferrals.
- Income Tax Expense increased $3 million primarily due to an increase in pretax book income, partially offset by changes in certain book/tax differences accounted for on a flow-through basis.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Reconciliation of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2008
Income Before Extraordinary Loss
(in millions)

Nine Months Ended September 30, 2007		$ 98
Changes in Gross Margin:		
Retail Margins	19	
Off-system Sales	32	
Other	1	
Total Change in Gross Margin		52
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	12	
Depreciation and Amortization	(44)	
Taxes Other Than Income Taxes	(5)	
Carrying Costs Income	16	
Other Income	7	
Interest Expense	(17)	
Total Change in Operating Expenses and Other		(31)
Income Tax Expense		2
Nine Months Ended September 30, 2008		$ 121

Income Before Extraordinary Loss increased $23 million to $121 million in 2008 primarily due to an increase in Gross Margin of $52 million, partially offset by a $31 million increase in Operating Expenses and Other.

The major components of the change 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 $19 million primarily due to the impact of the Virginia base rate order issued in May 2007 which included a 2007 provision for revenue refund in addition to an increase in the recovery of E&R costs in Virginia and construction financing costs in West Virginia. These increases were partially offset by an increase in sharing of off-system sales margins with customers and higher capacity settlement expenses under the Interconnection Agreement.
- Margins from Off-system Sales increased $32 million primarily due to increased physical sales margins driven by higher prices, partially offset by lower trading margins.

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

- Other Operation and Maintenance expenses decreased $12 million primarily due to the following:
  - A $26 million decrease resulting from a settlement agreement in the third quarter 2007 related to alleged violations of the NSR provisions of the CAA. The $26 million represents APCo's allocation of the settlement.
  - A $9 million decrease related to the establishment of a regulatory asset in the third quarter 2008 for Virginia's share of previously expended NSR settlement costs. See "Virginia E&R Cost Recovery Filing" section of Note 3.

  These decreases were partially offset by:
  - A $7 million increase in employee-related expenses.
  - A $10 million increase in overhead line maintenance expense due to right-of-way clearing and storm damage.
- Depreciation and Amortization expenses increased $44 million primarily due to $22 million in favorable adjustments made in the second quarter 2007 for APCo's Virginia base rate order and a $15 million increase in amortization of carrying charges and depreciation expense that are being collected through the Virginia E&R surcharges.
- Taxes Other Than Income Taxes increased $5 million primarily due to favorable franchise tax return adjustments recorded in 2007.
- Carrying Costs Income increased $16 million due to an increase in Virginia E&R deferrals.
- Other Income increased $7 million primarily due to higher interest income related to a tax refund in 2008 and other tax adjustments.
- Interest Expense increased $17 million primarily due to a $26 million increase in interest expense from long-term debt issuances, partially offset by a $7 million decrease in interest expense primarily related to interest on the Virginia provision for refund recorded in the second quarter of 2007.
- Income Tax Expense decreased $2 million primarily due to a decrease in state income taxes and changes in certain book/tax differences accounted for on a flow-through basis, partially offset by an increase in pretax book income.

Financial Condition

Credit Ratings

S&P currently has APCo on stable outlook, while Fitch placed APCo on negative outlook in the second quarter of 2008 and Moody's placed APCo on negative outlook in the first quarter of 2008. Current ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB+

If APCo receives an upgrade from any of the rating agencies listed above, its borrowing costs could decrease. If APCo receives a downgrade from any of the rating agencies listed above, it borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the nine months ended September 30, 2008 and 2007 were as follows:

	2008	2007
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 2,195	$ 2,318
Cash Flows from (Used for):		
Operating Activities	208,445	221,534
Investing Activities	(472,029)	(570,019)
Financing Activities	263,376	347,436
Net Decrease in Cash and Cash Equivalents	(208)	(1,049)
Cash and Cash Equivalents at End of Period	$ 1,987	$ 1,269

Operating Activities

Net Cash Flows from Operating Activities were $208 million in 2008. APCo produced income of $121 million during the period and had noncash expense items of $187 million for Depreciation and Amortization, $111 million for Deferred Income Taxes and $39 million for Carrying Costs Income. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a $114 million outflow in Fuel Over/Under-Recovery, Net as a result of a net under recovery of fuel cost in both Virginia and West Virginia due to higher fuel costs.

Net Cash Flows from Operating Activities were $222 million in 2007. APCo produced income of $19 million during the period and had noncash expense items of $142 million for Depreciation and Amortization, $79 million for Extraordinary Loss for the Reapplication of Regulatory Accounting for Generation and $23 million for Carrying Cost Income. The other changes in assets and liabilities represent items that had a prior period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital had no significant items in 2007.

Investing Activities

Net Cash Flows Used for Investing Activities during 2008 and 2007 were $472 million and $570 million, respectively. Construction Expenditures were $488 million and $538 million in 2008 and 2007, respectively, primarily related to transmission and distribution service reliability projects, as well as environmental upgrades for both periods. Environmental upgrades includes the installation of the flue gas desulfurization equipment at the Amos and Mountaineer Plants. In February 2007, environmental upgrades were completed for the Mountaineer Plant. For the remainder of 2008, APCo expects construction expenditures to be approximately $250 million.

Financing Activities

Net Cash Flows from Financing Activities were $263 million in 2008. APCo received capital contributions from the Parent of $175 million. APCo issued $500 million of Senior Unsecured Notes in March 2008, $125 million of Pollution Control Bonds in June 2008 and $70 million of Pollution Control Bonds in September 2008. These increases were partially offset by the retirement of $213 million of Pollution Control Bonds and $200 million of Senior Unsecured Notes in the second quarter of 2008. In addition, APCo had a net decrease of $182 million in borrowings from the Utility Money Pool.

Net Cash Flows from Financing Activities in 2007 were $347 million primarily due to the issuance of $75 million of Pollution Control Bonds in May 2007 and the issuance of $500 million of Senior Unsecured Notes in August 2007, net of retirement of $125 million of Senior Unsecured Notes in June 2007. APCo also reduced its short-term borrowings from the Utility Money Pool by $35 million.

Financing Activity

Long-term debt issuances, retirements and principal payments made during the first nine months of 2008 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Pollution Control Bonds	$ 40,000	4.85	2019
Pollution Control Bonds	30,000	4.85	2019
Pollution Control Bonds	75,000	Variable	2036
Pollution Control Bonds	50,275	Variable	2036
Senior Unsecured Notes	500,000	7.00	2038

Retirements and Principal Payments

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
	(in thousands)	(%)	
Pollution Control Bonds	$ 40,000	Variable	2019
Pollution Control Bonds	30,000	Variable	2019
Pollution Control Bonds	17,500	Variable	2021
Pollution Control Bonds	50,275	Variable	2036
Pollution Control Bonds	75,000	Variable	2037
Senior Unsecured Notes	200,000	3.60	2008
Other	11	13.718	2026

Liquidity

In recent months, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting APCo’s access to capital, liquidity and cost of capital. The uncertainties in the credit markets could have significant implications on APCo since it relies on continuing access to capital to fund operations and capital expenditures.

APCo participates in the Utility Money Pool, which provides access to AEP’s liquidity. APCo has $150 million of Senior Unsecured Notes that will mature in 2009. To the extent refinancing is unavailable due to the challenging credit markets, APCo will rely upon cash flows from operations and access to the Utility Money Pool to fund its maturity, continuing operations and capital expenditures.

Summary Obligation Information

A summary of contractual obligations is included in the 2007 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in “Cash Flow” and “Financing Activity” above and letters of credit. In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. As of September 30, 2008, $127 million of letters of credit were issued by APCo under the 3-year credit agreement to support variable rate demand notes.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2007 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page H-1. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for additional discussion of relevant factors.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2007 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on APCo.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in APCo's Condensed Consolidated Balance Sheet as of September 30, 2008 and the reasons for changes in total MTM value as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of September 30, 2008
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 81,386	$ 4,104	$ -	$ (3,532)	$ 81,958
Noncurrent Assets	58,881	1,036	-	(4,718)	55,199
Total MTM Derivative Contract Assets	140,267	5,140	-	(8,250)	137,157
Current Liabilities	(69,529)	(2,996)	(3,127)	547	(75,105)
Noncurrent Liabilities	(29,631)	-	(3,194)	50	(32,775)
Total MTM Derivative Contract Liabilities	(99,160)	(2,996)	(6,321)	597	(107,880)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 41,107	$ 2,144	$ (6,321)	$ (7,653)	$ 29,277

(a) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2008
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2007	$	45,870
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(13,569)
Fair Value of New Contracts at Inception When Entered During the Period (a)		-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)		564
Changes in Fair Value Due to Market Fluctuations During the Period (c)		(165)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		8,407
Total MTM Risk Management Contract Net Assets		41,107
Net Cash Flow & Fair Value Hedge Contracts		2,144
DETM Assignment (e)		(6,321)
Collateral Deposits		(7,653)
Ending Net Risk Management Assets at September 30, 2008	$	29,277

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.

(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

(e) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

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

The following table presents the maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash:

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of September 30, 2008
(in thousands)

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ (998)	$ (2,295)	$ (21)	$ -	$ -	$ -	$ (3,314)
Level 2 (b)	1,480	18,258	12,918	1,662	485	-	34,803
Level 3 (c)	(3,850)	666	(1,881)	272	152	-	(4,641)
Total	(3,368)	16,629	11,016	1,934	637	-	26,848
Dedesignated Risk Management Contracts (d)	1,403	4,720	4,681	1,823	1,632	-	14,259
Total MTM Risk Management Contract Net Assets (Liabilities)	$ (1,965)	$ 21,349	$ 15,697	$ 3,757	$ 2,269	$ -	$ 41,107

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.

(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

(d) Dedesignated Risk Management Contracts are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized into Revenues over the remaining life of the contract.

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

APCo is exposed to market fluctuations in energy commodity prices impacting power operations. Management monitors these risks on future operations and may use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. Management does not hedge all commodity price risk.

Management uses interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate risk.

Management uses foreign currency derivatives to lock in prices on certain forecasted transactions denominated in foreign currencies where deemed necessary, and designates qualifying instruments as cash flow hedges. Management does not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on APCo's Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2007 to September 30, 2008. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2008
(in thousands)

	Power	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2007	$ 783	$ (6,602)	$ (125)	$ (5,944)
Changes in Fair Value	670	(3,114)	68	(2,376)
Reclassifications from AOCI for Cash Flow Hedges Settled	(118)	1,231	5	1,118
Ending Balance in AOCI September 30, 2008	$ 1,335	$ (8,485)	$ (52)	$ (7,202)

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

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at September 30, 2008, a near term typical change in commodity prices is not expected to have a material effect on APCo's 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 periods indicated:

Nine Months Ended September 30, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$725	$1,096	$416	$161	$455	$2,328	$569	$117

Management back-tests its 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. Management's backtesting results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes APCo's VaR calculation is conservative.

As APCo's VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand its exposure to extreme price moves. Management employs a historically-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translate into the largest potential mark-to-market loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which APCo'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. The estimated EaR on APCo's debt portfolio was $4.3 million.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended 2008	Three Months Ended 2007	Nine Months Ended 2008	Nine Months Ended 2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 719,295	$ 639,830	$ 1,926,841	$ 1,740,565
Sales to AEP Affiliates	74,632	64,099	262,230	181,015
Other	4,906	2,647	12,186	8,134
TOTAL	798,833	706,576	2,201,257	1,929,714
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	220,955	200,702	554,022	535,906
Purchased Electricity for Resale	71,075	47,430	167,205	117,708
Purchased Electricity from AEP Affiliates	219,595	171,288	595,433	443,519
Other Operation	66,316	94,190	210,262	236,944
Maintenance	51,292	49,708	161,371	146,875
Depreciation and Amortization	62,364	51,864	186,528	142,100
Taxes Other Than Income Taxes	24,319	23,561	72,414	67,811
TOTAL	715,916	638,743	1,947,235	1,690,863
OPERATING INCOME	82,917	67,833	254,022	238,851
Other Income (Expense):				
Interest Income	1,945	510	7,541	1,539
Carrying Costs Income	11,924	8,701	38,921	22,817
Allowance for Equity Funds Used During Construction	2,130	1,084	6,278	5,442
Interest Expense	(47,385)	(44,980)	(138,644)	(121,758)
INCOME BEFORE INCOME TAX EXPENSE	51,531	33,148	168,118	146,891
Income Tax Expense	12,516	9,090	47,508	49,325
INCOME BEFORE EXTRAORDINARY LOSS	39,015	24,058	120,610	97,566
Extraordinary Loss – Reapplication of Regulatory Accounting for Generation, Net of Tax	-	-	-	(78,763)
NET INCOME	39,015	24,058	120,610	18,803
Preferred Stock Dividend Requirements Including Capital Stock Expense	238	238	714	714
EARNINGS APPLICABLE TO COMMON STOCK	$ 38,777	$ 23,820	$ 119,896	$ 18,089

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 260,458	$ 1,024,994	$ 805,513	$ (54,791)	$ 2,036,174
FIN 48 Adoption, Net of Tax			(2,685)		(2,685)
Common Stock Dividends			(25,000)		(25,000)
Preferred Stock Dividends			(600)		(600)
Capital Stock Expense		117	(114)		3
TOTAL					2,007,892
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $539				(1,000)	(1,000)
SFAS 158 Costs Established as a Regulatory Asset Related to the Reapplication of SFAS 71, Net of Tax of $6,055				11,245	11,245
NET INCOME			18,803		18,803
TOTAL COMPREHENSIVE INCOME					29,048
SEPTEMBER 30, 2007	$ 260,458	$ 1,025,111	$ 795,917	$ (44,546)	$ 2,036,940
DECEMBER 31, 2007	$ 260,458	$ 1,025,149	$ 831,612	$ (35,187)	$ 2,082,032
EITF 06-10 Adoption, Net of Tax of $1,175			(2,181)		(2,181)
SFAS 157 Adoption, Net of Tax of $154			(286)		(286)
Capital Contribution from Parent		175,000			175,000
Preferred Stock Dividends			(599)		(599)
Capital Stock Expense		115	(115)		-
TOTAL					2,253,966
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $677				(1,258)	(1,258)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,346				2,499	2,499
NET INCOME			120,610		120,610
TOTAL COMPREHENSIVE INCOME					121,851
SEPTEMBER 30, 2008	$ 260,458	$ 1,200,264	$ 949,041	$ (33,946)	$ 2,375,817

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,987	$ 2,195
Accounts Receivable:		
Customers	204,692	176,834
Affiliated Companies	96,277	113,582
Accrued Unbilled Revenues	43,333	38,397
Miscellaneous	1,923	2,823
Allowance for Uncollectible Accounts	(16,224)	(13,948)
Total Accounts Receivable	330,001	317,688
Fuel	80,853	82,203
Materials and Supplies	74,552	76,685
Risk Management Assets	81,958	62,955
Regulatory Asset for Under-Recovered Fuel Costs	90,111	-
Prepayments and Other	60,431	16,369
TOTAL	719,893	558,095
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,655,253	3,625,788
Transmission	1,739,018	1,675,081
Distribution	2,453,323	2,372,687
Other	362,985	351,827
Construction Work in Progress	947,101	713,063
Total	9,157,680	8,738,446
Accumulated Depreciation and Amortization	2,662,328	2,591,833
TOTAL - NET	6,495,352	6,146,613
OTHER NONCURRENT ASSETS		
Regulatory Assets	712,001	652,739
Long-term Risk Management Assets	55,199	72,366
Deferred Charges and Other	179,054	191,871
TOTAL	946,254	916,976
TOTAL ASSETS	$ 8,161,499	$ 7,621,684

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2008 and December 31, 2007
(Unaudited)

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 93,558	$ 275,257
Accounts Payable:		
General	290,320	241,871
Affiliated Companies	105,647	106,852
Long-term Debt Due Within One Year – Nonaffiliated	150,016	239,732
Risk Management Liabilities	75,105	51,708
Customer Deposits	51,243	45,920
Accrued Taxes	34,154	58,519
Accrued Interest	68,110	41,699
Other	98,950	139,476
TOTAL	967,103	1,201,034
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,873,980	2,507,567
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	32,775	47,357
Deferred Income Taxes	1,073,269	948,891
Regulatory Liabilities and Deferred Investment Tax Credits	509,068	505,556
Deferred Credits and Other	211,735	211,495
TOTAL	4,800,827	4,320,866
TOTAL LIABILITIES	5,767,930	5,521,900
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,752	17,752
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	1,200,264	1,025,149
Retained Earnings	949,041	831,612
Accumulated Other Comprehensive Income (Loss)	(33,946)	(35,187)
TOTAL	2,375,817	2,082,032
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 8,161,499	$ 7,621,684

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 120,610	$ 18,803
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	186,528	142,100
Deferred Income Taxes	111,297	32,021
Extraordinary Loss, Net of Tax	-	78,763
Carrying Costs Income	(38,921)	(22,817)
Allowance for Equity Funds Used During Construction	(6,278)	(5,442)
Mark-to-Market of Risk Management Contracts	7,450	(1,949)
Change in Other Noncurrent Assets	(24,670)	(9,185)
Change in Other Noncurrent Liabilities	(12,565)	27,247
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(12,313)	(87)
Fuel, Materials and Supplies	3,483	(11,387)
Accounts Payable	41,869	(38,724)
Accrued Taxes, Net	(51,208)	(9,990)
Accrued Interest	26,411	28,596
Fuel Over/Under-Recovery, Net	(113,748)	35,770
Other Current Assets	(17,202)	(21,483)
Other Current Liabilities	(12,298)	(20,702)
Net Cash Flows from Operating Activities	208,445	221,534
INVESTING ACTIVITIES		
Construction Expenditures	(487,797)	(537,930)
Change in Other Cash Deposits, Net	(18)	(29)
Change in Advances to Affiliates, Net	-	(38,573)
Proceeds from Sales of Assets	15,786	6,713
Other	-	(200)
Net Cash Flows Used for Investing Activities	(472,029)	(570,019)
FINANCING ACTIVITIES		
Capital Contribution from Parent	175,000	-
Issuance of Long-term Debt – Nonaffiliated	686,512	568,778
Change in Advances from Affiliates, Net	(181,699)	(34,975)
Retirement of Long-term Debt – Nonaffiliated	(412,786)	(125,009)
Retirement of Cumulative Preferred Stock	-	(9)
Principal Payments for Capital Lease Obligations	(3,052)	(3,316)
Amortization of Funds from Amended Coal Contract	-	(32,433)
Dividends Paid on Common Stock	-	(25,000)
Dividends Paid on Cumulative Preferred Stock	(599)	(600)
Net Cash Flows from Financing Activities	263,376	347,436
Net Decrease in Cash and Cash Equivalents	(208)	(1,049)
Cash and Cash Equivalents at Beginning of Period	2,195	2,318
Cash and Cash Equivalents at End of Period	$ 1,987	$ 1,269
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 110,349	$ 86,199
Net Cash Paid (Received) for Income Taxes	(26,330)	6,688
Noncash Acquisitions Under Capital Leases	1,246	2,738
Construction Expenditures Included in Accounts Payable at September 30,	112,376	90,315

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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

The condensed notes to APCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo. The footnotes begin on page H-1.

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

Third Quarter of 2008 Compared to Third Quarter of 2007

Reconciliation of Third Quarter of 2007 to Third Quarter of 2008
Net Income
(in millions)

Third Quarter of 2007		$ 85
Changes in Gross Margin:		
Retail Margins	(4)	
Off-system Sales	5	
Transmission Revenues	1	
Total Change in Gross Margin		2
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(2)	
Depreciation and Amortization	(3)	
Taxes Other Than Income Taxes	(3)	
Interest Expense	(1)	
Other Income	2	
Total Change in Operating Expenses and Other		(7)
Income Tax Expense		2
Third Quarter of 2008		$ 82

Net Income decreased $3 million to $82 million in 2008. The key drivers of the decrease were a $7 million increase in Operating Expenses and Other, partially offset by a $2 million increase in Gross Margin and a $2 million decrease in Income Tax Expense.

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 decreased $4 million primarily due to:
  - A $23 million decrease in residential and commercial revenue primarily due to a 12% decrease in cooling degree days and the outages caused by the remnants of Hurricane Ike.
  - A $20 million decrease related to increased fuel, allowance and consumables expenses. CSPCo and OPCo have applied for an active fuel clause in their Ohio ESP to be effective January 1, 2009.
  - A $4 million increase in capacity settlement charges under the Interconnection Agreement due to a change in relative peak demands.

  These decreases were partially offset by a $44 million increase related to a net increase in rates implemented.
- Margins from Off-system Sales increased $5 million primarily due to increased physical sales margins driven by higher prices, partially offset by lower trading margins.

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

- Other Operation and Maintenance expenses increased $2 million due to:
  - A $9 million increase in recoverable PJM costs.
  - A $4 million increase in recoverable customer account expenses related to the Universal Service Fund for customers who qualify for payment assistance.
  - A $3 million increase in employee-related expenses.

  These increases were partially offset by a $15 million decrease resulting from a settlement agreement in the third quarter 2007 related to alleged violations of the NSR provisions of the CAA. The $15 million represents CSPCo's allocation of the settlement.
- Depreciation and Amortization increased $3 million primarily due to a greater depreciation base related to environmental improvements placed in service.
- Taxes Other Than Income Taxes increased $3 million due to property tax adjustments.
- Income Tax Expense decreased $2 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Reconciliation of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2008
Net Income
(in millions)

Nine Months Ended September 30, 2007		$ 212
Changes in Gross Margin:		
Retail Margins	36	
Off-system Sales	24	
Transmission Revenues	3	
Total Change in Gross Margin		63
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(45)	
Depreciation and Amortization	1	
Taxes Other Than Income Taxes	(12)	
Interest Expense	(6)	
Other Income	5	
Total Change in Operating Expenses and Other		(57)
Income Tax Expense		(4)
Nine Months Ended September 30, 2008		$ 214

Net Income increased $2 million to $214 million in 2008. The key drivers of the increase were a $63 million increase in Gross Margin primarily offset by a $57 million increase in Operating Expenses and Other and a $4 million increase in Income Tax Expense.

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 $36 million primarily due to:
  - A $106 million increase related to a net increase in rates implemented.
  - A $35 million decrease in capacity settlement charges related to CSPCo's Unit Power Agreement (UPA) for AEGCo's Lawrenceburg Plant, which began in May 2007, and to the April 2007 acquisition of the Darby Plant.
  - A $15 million increase in industrial revenue related to higher usage by Ormet.

  These increases were partially offset by:
  - A $59 million decrease related to increased fuel, allowance and consumables expenses. CSPCo and OPCo have applied for an active fuel clause in their Ohio ESP to be effective January 1, 2009.
  - A $35 million decrease in residential and commercial revenue primarily due to a 16% decrease in cooling and a 6% decrease in heating degree days.
- Margins from Off-system Sales increased $24 million primarily due to increased physical sales margins driven by higher prices, partially offset by lower trading margins.

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

- Other Operation and Maintenance expenses increased $45 million primarily due to:
  - A $17 million increase in recoverable PJM expenses.
  - A $13 million increase in expenses related to CSPCo's UPA for AEGCo's Lawrenceburg Plant which began in May 2007.
  - A $10 million increase in steam plant maintenance expenses primarily related to work performed at the Conesville Plant.
  - A $9 million increase in recoverable customer account expenses related to the Universal Service Fund for customers who qualify for payment assistance.
  - A $4 million increase in boiler plant removal expenses primarily related to work performed at the Conesville Plant.

  These increases were partially offset by a $15 million decrease resulting from a settlement agreement in the third quarter 2007 related to alleged violations of the NSR provisions of the CAA. The $15 million represents CSPCo's allocation of the settlement.
- Taxes Other Than Income Taxes increased $12 million due to property tax adjustments.
- Interest Expense increased $6 million due to increased long-term borrowings.
- Other Income increased $5 million primarily due to interest income on federal tax refunds.
- Income Tax Expense increased $4 million primarily due to an increase in pretax book income and state income taxes.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2007 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion and analysis within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section for disclosures about risk management activities.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which CSPCo'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. The estimated EaR on CSPCo's debt portfolio was $1.3 million.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2008	2007	2008	2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 633,325	$ 553,518	$ 1,638,705	$ 1,446,632
Sales to AEP Affiliates	29,032	52,331	111,553	110,700
Other	1,426	1,292	4,121	3,743
TOTAL	663,783	607,141	1,754,379	1,561,075
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	112,566	103,560	283,946	255,764
Purchased Electricity for Resale	63,441	49,619	150,637	113,765
Purchased Electricity from AEP Affiliates	139,017	107,386	343,699	278,715
Other Operation	87,358	83,625	245,379	207,300
Maintenance	23,039	24,250	80,705	73,537
Depreciation and Amortization	50,373	47,589	146,668	147,332
Taxes Other Than Income Taxes	44,533	41,382	130,078	117,760
TOTAL	520,327	457,411	1,381,112	1,194,173
OPERATING INCOME	143,456	149,730	373,267	366,902
Other Income (Expense):				
Interest Income	1,515	166	5,457	782
Carrying Costs Income	1,566	1,261	4,870	3,492
Allowance for Equity Funds Used During Construction	745	738	2,165	2,130
Interest Expense	(21,127)	(19,530)	(57,612)	(51,193)
INCOME BEFORE INCOME TAX EXPENSE	126,155	132,365	328,147	322,113
Income Tax Expense	44,493	46,911	113,939	109,656
NET INCOME	81,662	85,454	214,208	212,457
Capital Stock Expense	39	39	118	118
EARNINGS APPLICABLE TO COMMON STOCK	$ 81,623	$ 85,415	$ 214,090	$ 212,339

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 41,026	$ 580,192	$ 456,787	$ (21,988)	$ 1,056,017
FIN 48 Adoption, Net of Tax			(3,022)		(3,022)
Common Stock Dividends			(90,000)		(90,000)
Capital Stock Expense and Other		118	(118)		-
TOTAL					962,995
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,231				(2,285)	(2,285)
NET INCOME			212,457		212,457
TOTAL COMPREHENSIVE INCOME					210,172
SEPTEMBER 30, 2007	$ 41,026	$ 580,310	$ 576,104	$ (24,273)	$ 1,173,167
DECEMBER 31, 2007	$ 41,026	$ 580,349	$ 561,696	$ (18,794)	$ 1,164,277
EITF 06-10 Adoption, Net of Tax of $589			(1,095)		(1,095)
SFAS 157 Adoption, Net of Tax of $170			(316)		(316)
Common Stock Dividends			(87,500)		(87,500)
Capital Stock Expense		118	(118)		-
TOTAL					1,075,366
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $582				1,080	1,080
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $456				846	846
NET INCOME			214,208		214,208
TOTAL COMPREHENSIVE INCOME					216,134
SEPTEMBER 30, 2008	$ 41,026	$ 580,467	$ 686,875	$ (16,868)	$ 1,291,500

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,956	$ 1,389
Other Cash Deposits	31,964	53,760
Advances to Affiliates	21,833	-
Accounts Receivable:		
Customers	65,581	57,268
Affiliated Companies	27,933	32,852
Accrued Unbilled Revenues	24,078	14,815
Miscellaneous	11,256	9,905
Allowance for Uncollectible Accounts	(2,814)	(2,563)
Total Accounts Receivable	126,034	112,277
Fuel	30,081	35,849
Materials and Supplies	34,979	36,626
Emission Allowances	7,884	16,811
Risk Management Assets	40,842	33,558
Prepayments and Other	31,984	9,960
TOTAL	327,557	300,230
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,317,357	2,072,564
Transmission	568,380	510,107
Distribution	1,600,323	1,552,999
Other	211,475	198,476
Construction Work in Progress	322,885	415,327
Total	5,020,420	4,749,473
Accumulated Depreciation and Amortization	1,758,415	1,697,793
TOTAL - NET	3,262,005	3,051,680
OTHER NONCURRENT ASSETS		
Regulatory Assets	204,203	235,883
Long-term Risk Management Assets	30,268	41,852
Deferred Charges and Other	125,071	181,563
TOTAL	359,542	459,298
TOTAL ASSETS	$ 3,949,104	$ 3,811,208

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
September 30, 2008 and December 31, 2007
(Unaudited)

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 95,199
Accounts Payable:		
General	145,733	113,290
Affiliated Companies	53,532	65,292
Long-term Debt Due Within One Year – Nonaffiliated	-	112,000
Risk Management Liabilities	37,331	28,237
Customer Deposits	29,995	43,095
Accrued Taxes	153,391	179,831
Other	84,432	96,892
TOTAL	504,414	733,836
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,343,491	1,086,224
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	18,061	27,419
Deferred Income Taxes	447,465	437,306
Regulatory Liabilities and Deferred Investment Tax Credits	155,332	165,635
Deferred Credits and Other	88,841	96,511
TOTAL	2,153,190	1,913,095
TOTAL LIABILITIES	2,657,604	2,646,931
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,467	580,349
Retained Earnings	686,875	561,696
Accumulated Other Comprehensive Income (Loss)	(16,868)	(18,794)
TOTAL	1,291,500	1,164,277
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 3,949,104	$ 3,811,208

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 214,208	$ 212,457
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	146,668	147,332
Deferred Income Taxes	8,981	(13,959)
Carrying Costs Income	(4,870)	(3,492)
Allowance for Equity Funds Used During Construction	(2,165)	(2,130)
Mark-to-Market of Risk Management Contracts	5,326	1,321
Deferred Property Taxes	65,763	57,890
Change in Other Noncurrent Assets	(7,942)	(29,199)
Change in Other Noncurrent Liabilities	(4,081)	2,713
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(13,757)	(13,040)
Fuel, Materials and Supplies	7,415	(2,332)
Accounts Payable	(2,650)	(13,336)
Customer Deposits	(13,100)	10,212
Accrued Taxes, Net	(26,358)	(44,295)
Other Current Assets	(13,178)	(1,490)
Other Current Liabilities	(14,018)	8,817
Net Cash Flows from Operating Activities	346,242	317,469
INVESTING ACTIVITIES		
Construction Expenditures	(304,175)	(246,130)
Change in Other Cash Deposits, Net	21,796	(44,360)
Change in Advances to Affiliates, Net	(21,833)	-
Acquisition of Darby Plant	-	(102,032)
Proceeds from Sales of Assets	1,287	1,016
Net Cash Flows Used for Investing Activities	(302,925)	(391,506)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	346,407	44,257
Change in Advances from Affiliates, Net	(95,199)	122,347
Retirement of Long-term Debt – Nonaffiliated	(204,245)	-
Principal Payments for Capital Lease Obligations	(2,213)	(2,191)
Dividends Paid on Common Stock	(87,500)	(90,000)
Net Cash Flows from (Used for) Financing Activities	(42,750)	74,413
Net Increase in Cash and Cash Equivalents	567	376
Cash and Cash Equivalents at Beginning of Period	1,389	1,319
Cash and Cash Equivalents at End of Period	$ 1,956	$ 1,695
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 57,004	$ 53,464
Net Cash Paid for Income Taxes	53,682	93,709
Noncash Acquisitions Under Capital Leases	1,374	1,900
Construction Expenditures Included in Accounts Payable at September 30,	51,997	34,630
Noncash Assumption of Liabilities Related to Acquisition of Darby Plant	-	2,339

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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

The condensed notes to CSPCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to CSPCo. The footnotes begin on page H-1.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

Third Quarter of 2008 Compared to Third Quarter of 2007

Reconciliation of Third Quarter of 2007 to Third Quarter of 2008
Net Income
(in millions)

Third Quarter of 2007		$ 49
Changes in Gross Margin:		
Retail Margins	(16)	
FERC Municipals and Cooperatives	(2)	
Off-system Sales	4	
Other	10	
Total Change in Gross Margin		(4)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(2)	
Depreciation and Amortization	4	
Other Income	(1)	
Interest Expense	(2)	
Total Change in Operating Expenses and Other		(1)
Income Tax Expense		2
Third Quarter of 2008		$ 46

Net Income decreased $3 million to $46 million in 2008. The key drivers of the decrease were a $4 million decrease in Gross Margin and a $1 million increase in Operating Expenses and Other, partially offset by a $2 million decrease in Income Tax Expense.

The major components of the decrease 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 decreased $16 million primarily due to lower retail sales reflecting weather conditions as cooling degree days decreased at least 12% in both the Indiana and Michigan jurisdictions.
- Margins from Off-system Sales increased $4 million primarily due to increased physical sales margins driven by higher prices, partially offset by lower trading margins.
- Other revenues increased $10 million primarily due to increased River Transportation Division (RTD) revenues for barging services. RTD's related expenses which offset the RTD revenue increase are included in Other Operation on the Condensed Consolidated Statements of Income resulting in earning only a return approved under a regulatory order.

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

- Other Operation and Maintenance expenses increased $2 million primarily due to higher operation and maintenance expenses for RTD of $11 million caused by increased barging activity and increased cost of fuel in 2008, partially offset by a $9 million decrease in coal-fired plant operation expenses. A settlement agreement related to alleged violations of the NSR provisions of the CAA, of which $14 million was allocated to I&M, increased 2007 Other Operation and Maintenance expenses.
- Depreciation and Amortization expense decreased $4 million primarily due to reduced depreciation rates reflecting longer estimated lives for Cook and Tanners Creek Plants. Depreciation rates were reduced for the FERC and Michigan jurisdictions in October 2007. See "Michigan Depreciation Study Filing" section of Note 4 in the 2007 Annual Report.
- Income Tax Expense decreased $2 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Reconciliation of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2008
Net Income
(in millions)

Nine Months Ended September 30, 2007		$ 109
Changes in Gross Margin:		
Retail Margins	(19)	
FERC Municipals and Cooperatives	4	
Off-system Sales	18	
Transmission Revenues	(2)	
Other	31	
Total Change in Gross Margin		32
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(24)	
Depreciation and Amortization	50	
Taxes Other Than Income Taxes	(3)	
Total Change in Operating Expenses and Other		23
Income Tax Expense		(13)
Nine Months Ended September 30, 2008		$ 151

Net Income increased $42 million to $151 million in 2008. The key drivers of the increase were a $32 million increase in Gross Margin and a $23 million decrease in Operating Expenses and Other, partially offset by a $13 million increase in Income Tax Expense.

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 decreased $19 million primarily due to lower retail sales reflecting weather conditions as cooling degree days decreased at least 19% in both the Indiana and Michigan jurisdictions.
- Margins from Off-system Sales increased $18 million primarily due to increased physical sales margins driven by higher prices, partially offset by lower trading margins.
- Other revenues increased $31 million primarily due to increased RTD revenues for barging services. RTD's related expenses which offset the RTD revenue increase are included in Other Operation on the Condensed Consolidated Statements of Income resulting in earning only a return approved under regulatory order.

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

- Other Operation and Maintenance expenses increased $24 million primarily due to higher operation and maintenance expenses for RTD of $31 million caused by increased barging activity and increased cost of fuel and an increase in nuclear operation and maintenance expenses of $16 million. Lower coal-fired plant operation and maintenance expenses of $18 million, including the NSR settlement, and a $5 million decrease in accretion expense partially offset the increases.
- Depreciation and Amortization expense decreased $50 million primarily due to the reduced depreciation rates in all jurisdictions. Depreciation rates were reduced for the Indiana jurisdiction in June 2007 and the FERC and Michigan jurisdictions in October 2007. See "Indiana Depreciation Study Filing" and "Michigan Depreciation Study Filing" sections of Note 4 in the 2007 Annual Report.
- Income Tax Expense increased $13 million primarily due to an increase in pretax book income and a decrease in amortization of investment tax credits, partially offset by changes in certain book/tax differences accounted for on a flow-through basis.

Cook Plant Unit 1 Fire and Shutdown

Cook Plant Unit 1 (Unit 1) is a 1,030 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations likely caused by blade failure which resulted in a fire on the electric generator. This equipment is in the turbine building and is separate and isolated from the nuclear reactor. The steam turbines that caused the vibration were installed in 2006 and are under warranty from the vendor. The warranty provides for the replacement of the turbines if the damage was caused by a defect in the design or assembly of the turbines. I&M is also working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and turbine vendor to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. Management cannot estimate the ultimate costs of the outage at this time. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Management's preliminary analysis indicates that Unit 1 could resume operations as early as late first quarter/early second quarter of 2009 or as late as the second half of 2009, depending upon whether the damaged components can be repaired or whether they need to be replaced.

I&M maintains property insurance through NEIL with a $1 million deductible. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12 week deductible period, I&M is entitled to weekly payments of $3.5 million during the outage period for a covered loss. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2007 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion and analysis within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section for disclosures about risk management activities.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which I&M'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. The estimated EaR on I&M's debt portfolio was $5.7 million.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended 2008	Three Months Ended 2007	Nine Months Ended 2008	Nine Months Ended 2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 513,548	$ 478,907	$ 1,370,158	$ 1,286,223
Sales to AEP Affiliates	72,295	56,262	232,734	186,653
Other – Affiliated	31,792	16,250	84,268	43,488
Other – Nonaffiliated	3,388	7,757	13,659	21,718
TOTAL	621,023	559,176	1,700,819	1,538,082
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	141,563	103,740	351,300	290,507
Purchased Electricity for Resale	39,427	26,580	87,351	63,830
Purchased Electricity from AEP Affiliates	112,060	96,451	296,559	249,755
Other Operation	136,875	129,439	381,928	367,483
Maintenance	52,573	58,502	156,402	146,657
Depreciation and Amortization	31,822	35,604	95,301	145,801
Taxes Other Than Income Taxes	19,992	19,704	60,236	56,936
TOTAL	534,312	470,020	1,429,077	1,320,969
OPERATING INCOME	86,711	89,156	271,742	217,113
Other Income (Expense):				
Other Income	880	1,986	4,621	4,273
Interest Expense	(20,629)	(18,312)	(56,977)	(57,744)
INCOME BEFORE INCOME TAX EXPENSE	66,962	72,830	219,386	163,642
Income Tax Expense	21,326	23,706	68,348	55,020
NET INCOME	45,636	49,124	151,038	108,622
Preferred Stock Dividend Requirements	85	85	255	255
EARNINGS APPLICABLE TO COMMON STOCK	$ 45,551	$ 49,039	$ 150,783	$ 108,367

The common stock of I&M is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 56,584	$ 861,290	$ 386,616	$ (15,051)	$ 1,289,439
FIN 48 Adoption, Net of Tax			327		327
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(255)		(255)
Gain on Reacquired Preferred Stock		1			1
TOTAL					1,259,512
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $941				(1,747)	(1,747)
NET INCOME			108,622		108,622
TOTAL COMPREHENSIVE INCOME					106,875
SEPTEMBER 30, 2007	$ 56,584	$ 861,291	$ 465,310	$ (16,798)	$ 1,366,387
DECEMBER 31, 2007	$ 56,584	$ 861,291	$ 483,499	$ (15,675)	$ 1,385,699
EITF 06-10 Adoption, Net of Tax of $753			(1,398)		(1,398)
Common Stock Dividends			(56,250)		(56,250)
Preferred Stock Dividends			(255)		(255)
TOTAL					1,327,796
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $967				1,795	1,795
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $178				331	331
NET INCOME			151,038		151,038
TOTAL COMPREHENSIVE INCOME					153,164
SEPTEMBER 30, 2008	$ 56,584	$ 861,291	$ 576,634	$ (13,549)	$ 1,480,960

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,328	$ 1,139
Accounts Receivable:		
Customers	82,788	70,995
Affiliated Companies	77,640	92,018
Accrued Unbilled Revenues	21,028	16,207
Miscellaneous	2,010	1,335
Allowance for Uncollectible Accounts	(3,200)	(2,711)
Total Accounts Receivable	180,266	177,844
Fuel	46,745	61,342
Materials and Supplies	143,245	141,384
Risk Management Assets	40,215	32,365
Accrued Tax Benefits	1,004	4,438
Prepayments and Other	35,829	11,091
TOTAL	448,632	429,603
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,512,424	3,529,524
Transmission	1,100,255	1,078,575
Distribution	1,262,017	1,196,397
Other (including nuclear fuel and coal mining)	655,257	626,390
Construction Work in Progress	173,062	122,296
Total	6,703,015	6,553,182
Accumulated Depreciation, Depletion and Amortization	3,000,898	2,998,416
TOTAL - NET	3,702,117	3,554,766
OTHER NONCURRENT ASSETS		
Regulatory Assets	251,451	246,435
Spent Nuclear Fuel and Decommissioning Trusts	1,291,986	1,346,798
Long-term Risk Management Assets	29,518	40,227
Deferred Charges and Other	118,574	128,623
TOTAL	1,691,529	1,762,083
TOTAL ASSETS	$ 5,842,278	$ 5,746,452

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2008 and December 31, 2007
(Unaudited)

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 224,071	$ 45,064
Accounts Payable:		
General	177,480	184,435
Affiliated Companies	64,970	61,749
Long-term Debt Due Within One Year – Nonaffiliated	50,000	145,000
Risk Management Liabilities	36,802	27,271
Customer Deposits	26,957	26,445
Accrued Taxes	60,111	60,995
Obligations Under Capital Leases	43,626	43,382
Other	133,267	130,232
TOTAL	817,284	724,573
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,377,115	1,422,427
Long-term Risk Management Liabilities	17,585	26,348
Deferred Income Taxes	382,374	321,716
Regulatory Liabilities and Deferred Investment Tax Credits	693,981	789,346
Asset Retirement Obligations	886,278	852,646
Deferred Credits and Other	178,621	215,617
TOTAL	3,535,954	3,628,100
TOTAL LIABILITIES	4,353,238	4,352,673
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,080	8,080
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	861,291	861,291
Retained Earnings	576,634	483,499
Accumulated Other Comprehensive Income (Loss)	(13,549)	(15,675)
TOTAL	1,480,960	1,385,699
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,842,278	$ 5,746,452

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 151,038	$ 108,622
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	95,301	145,801
Deferred Income Taxes	47,565	(9,235)
Amortization of Incremental Nuclear Refueling Outage Expenses, Net	834	14,450
Allowance for Equity Funds Used During Construction	(967)	(2,726)
Mark-to-Market of Risk Management Contracts	4,876	3,046
Amortization of Nuclear Fuel	72,453	48,360
Change in Other Noncurrent Assets	5,678	17,163
Change in Other Noncurrent Liabilities	38,568	33,995
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(2,422)	34,569
Fuel, Materials and Supplies	12,736	14,584
Accounts Payable	16,549	(27,015)
Accrued Taxes, Net	2,550	41,243
Other Current Assets	(24,736)	(4,595)
Other Current Liabilities	1,393	3,150
Net Cash Flows from Operating Activities	421,416	421,412
INVESTING ACTIVITIES		
Construction Expenditures	(221,538)	(191,110)
Purchases of Investment Securities	(413,538)	(561,509)
Sales of Investment Securities	362,773	505,620
Acquisitions of Nuclear Fuel	(99,110)	(73,112)
Proceeds from Sales of Assets and Other	3,376	670
Net Cash Flows Used for Investing Activities	(368,037)	(319,441)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	115,225	-
Change in Advances from Affiliates, Net	179,007	(66,939)
Retirement of Long-term Debt – Nonaffiliated	(262,000)	-
Retirement of Cumulative Preferred Stock	-	(2)
Principal Payments for Capital Lease Obligations	(28,917)	(3,954)
Dividends Paid on Common Stock	(56,250)	(30,000)
Dividends Paid on Cumulative Preferred Stock	(255)	(255)
Net Cash Flows Used for Financing Activities	(53,190)	(101,150)
Net Increase in Cash and Cash Equivalents	189	821
Cash and Cash Equivalents at Beginning of Period	1,139	1,369
Cash and Cash Equivalents at End of Period	$ 1,328	$ 2,190
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 57,086	$ 49,628
Net Cash Paid for Income Taxes	7,482	14,395
Noncash Acquisitions Under Capital Leases	3,279	5,847
Construction Expenditures Included in Accounts Payable at September 30,	26,150	23,935
Acquisition of Nuclear Fuel Included in Accounts Payable at September 30,	66,127	691

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to I&M's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M. The footnotes begin on page H-1.

OHIO POWER COMPANY CONSOLIDATED

Results of Operations

Third Quarter of 2008 Compared to Third Quarter of 2007

Reconciliation of Third Quarter of 2007 to Third Quarter of 2008
Net Income
(in millions)

Third Quarter of 2007		$	75
Changes in Gross Margin:			
Retail Margins	(48)		
Off-system Sales	11		
Other	3		
Total Change in Gross Margin			(34)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(2)		
Depreciation and Amortization	12		
Taxes Other Than Income Taxes	(1)		
Other Income	2		
Interest Expense	(4)		
Total Change in Operating Expenses and Other			7
Income Tax Expense			8
Third Quarter of 2008		$	56

Net Income decreased $19 million to $56 million in 2008. The key drivers of the decrease were a $34 million decrease in Gross Margin, partially offset by an $8 million decrease in Income Tax Expense and a $7 million decrease in Operating Expenses and Other.

The major components of the decrease 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 decreased $48 million primarily due to the following:
  - A $57 million decrease related to increased fuel and consumables expenses. CSPCo and OPCo have applied for an active fuel clause in their Ohio ESP to be effective January 1, 2009.
  - An $8 million decrease in residential revenue primarily due to an 18% decrease in cooling degree days and the outages caused by the remnants of Hurricane Ike.

  These decreases were partially offset by:
  - A $17 million increase related to a net increase in rates implemented.
  - A $10 million increase in capacity settlements under the Interconnection Agreement related to an increase in an affiliate's peak.
- Margins from Off-system Sales increased $11 million primarily due to increased physical sales margins driven by higher prices, partially offset by lower trading margins.
- Other revenues increased $3 million primarily due to increased gains on sales of emission allowances.

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

- Other Operation and Maintenance expenses increased $2 million primarily due to:
  - A $6 million increase in recoverable PJM expenses.
  - A $4 million increase in employee-related expenses.
  - A $4 million increase in recoverable customer account expenses related to the Universal Service Fund for customers who qualify for payment assistance.
  - A $3 million increase in operation and maintenance expenses related to service restoration expenses from the remnants of Hurricane Ike.
  - A $2 million increase in plant maintenance expenses.

  These increases were partially offset by a $17 million decrease resulting from a settlement agreement in the third quarter 2007 related to alleged violations of the NSR provisions of the CAA. The $17 million represents OPCo's allocation of the settlement.
- Depreciation and Amortization expense decreased $12 million primarily due to an $18 million decrease in amortization as a result of completion of amortization of regulatory assets in December 2007, partially offset by a $5 million increase in depreciation related to environmental improvements placed in service at the Cardinal Plant in 2008 and the Mitchell Plant in July 2007.
- Interest Expense increased $4 million primarily due to a decrease in the debt component of AFUDC as a result of Mitchell Plant and Cardinal Plant environmental improvements placed in service and higher interest rates on variable rate debt.
- Income Tax Expense decreased $8 million primarily due to a decrease in pretax book income.

<u>Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007</u>

Reconciliation of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2008
Net Income
(in millions)

Nine Months Ended September 30, 2007		$ 229
Changes in Gross Margin:		
Retail Margins	(55)	
Off-system Sales	34	
Other	12	
Total Change in Gross Margin		(9)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	8	
Depreciation and Amortization	42	
Carrying Costs Income	1	
Other Income	6	
Interest Expense	(20)	
Total Change in Operating Expenses and Other		37
Income Tax Expense		(10)
Nine Months Ended September 30, 2008		$ 247

Net Income increased $18 million to $247 million in 2008. The key drivers of the increase were a $37 million decrease in Operating Expenses and Other, partially offset by a $10 million increase in Income Tax Expense and a $9 million decrease in Gross Margin.

The major components of the decrease 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 decreased $55 million primarily due to the following:
  - A $105 million decrease related to increased fuel and consumables expenses. CSPCo and OPCo have applied for an active fuel clause in their Ohio ESP to be effective January 1, 2009.
  - A $9 million decrease in residential revenues primarily due to a 21% decrease in cooling degree days.

  These decreases were partially offset by:
  - A $42 million increase related to a net increase in rates implemented.
  - A $29 million increase related to coal contract amendments in 2008.
  - A $17 million increase in capacity settlements under the Interconnection Agreement related to an increase in an affiliate's peak.
- Margins from Off-system Sales increased $34 million primarily due to increased physical sales margins driven by higher prices and higher trading margins.
- Other revenues increased $12 million primarily due to increased gains on sales of emission allowances.

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

- Other Operation and Maintenance expenses decreased $8 million primarily due to:
  - A $20 million decrease in removal expenses related to planned outages at the Gavin and Mitchell Plants during 2007.
  - A $17 million decrease resulting from a settlement agreement in the third quarter 2007 related to alleged violations of the NSR provisions of the CAA. The $17 million represents OPCo's allocation of the settlement.
  - A $7 million decrease in overhead line maintenance expenses.

  These decreases were partially offset by:
  - A $13 million increase in recoverable PJM expenses.
  - An $11 million increase in recoverable customer account expenses related to the Universal Service Fund for customers who qualify for payment assistance.
  - A $7 million increase in maintenance expenses from planned and forced outages at various plants.
  - A $4 million increase in employee-related expenses.
- Depreciation and Amortization decreased $42 million primarily due to:
  - A $53 million decrease in amortization as a result of completion of amortization of regulatory assets in December 2007.
  - A $6 million decrease due to the amortization of IGCC pre-construction costs, which ended in the second quarter of 2007. The amortization of IGCC pre-construction costs was offset by a corresponding increase in Retail Margins in 2007.

  These decreases were partially offset by a $19 million increase in depreciation related to environmental improvements placed in service at the Cardinal Plant in 2008 and the Mitchell Plant in 2007.
- Interest Expense increased $20 million primarily due to a decrease in the debt component of AFUDC as a result of Mitchell Plant and Cardinal Plant environmental improvements placed in service, the issuance of additional long-term debt and higher interest rates on variable rate debt.
- Income Tax Expense increased $10 million primarily due to an increase in pretax book income.

Financial Condition

Credit Ratings

S&P and Fitch currently have OPCo on stable outlook, while Moody's placed OPCo on negative outlook in the first quarter of 2008. Current ratings are as follows:

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

If OPCo receives an upgrade from any of the rating agencies listed above, its borrowing costs could decrease. If OPCo receives a downgrade from any of the rating agencies listed above, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the nine months ended September 30, 2008 and 2007 were as follows:

	2008	2007
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 6,666	$ 1,625
Cash Flows from (Used for):		
Operating Activities	434,295	402,980
Investing Activities	(486,678)	(743,260)
Financing Activities	54,805	351,381
Net Increase in Cash and Cash Equivalents	2,422	11,101
Cash and Cash Equivalents at End of Period	$ 9,088	$ 12,726

Operating Activities

Net Cash Flows from Operating Activities were $434 million in 2008. OPCo produced Net Income of $247 million during the period and a noncash expense item of $212 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital and changes in the future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Accounts Payable had a $45 million inflow primarily due to increases in tonnage and prices per ton related to fuel and consumable purchases. Fuel, Materials and Supplies had a $48 million outflow due to price increases.

Net Cash Flows from Operating Activities were $403 million in 2007. OPCo produced Net Income of $229 million during the period and a noncash expense item of $253 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a prior period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The prior period activity in working capital included two significant items. Accounts Payable had a $60 million cash outflow partially due to emission allowance payments in January 2007, reduced accruals for Mitchell Plant environmental projects that went into service in 2007 and timing differences for payments to affiliates. Accounts Receivable, Net had a $33 million cash outflow partially due to the timing of collections of receivables.

Investing Activities

Net Cash Used for Investing Activities were $487 million and $743 million in 2008 and 2007, respectively. Construction Expenditures were $453 million and $751 million in 2008 and 2007, respectively, primarily related to environmental upgrades, as well as projects to improve service reliability for transmission and distribution. Environmental upgrades include the installation of selective catalytic reduction equipment and flue gas desulfurization projects at the Cardinal, Amos and Mitchell Plants. In 2007, environmental upgrades were completed for Units 1 and 2 at the Mitchell Plant. For the remainder of 2008, OPCo expects construction expenditures to be approximately $230 million.

Financing Activities

Net Cash Flows from Financing Activities were $55 million in 2008. OPCo issued $165 million of Pollution Control Bonds and $250 million of Senior Unsecured Notes. These increases were partially offset by the retirement of $250 million of Pollution Control Bonds and $13 million of Notes Payable – Nonaffiliated. OPCo also had a net decrease in borrowings of $102 million from the Utility Money Pool.

Net Cash Flows from Financing Activities were $351 million in 2007. OPCo issued $400 million of Senior Unsecured Notes and $65 million of Pollution Control Bonds. OPCo reduced borrowings by $96 million from the Utility Money Pool.

Financing Activity

Long-term debt issuances, retirements and principal payments made during the first nine months of 2008 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Pollution Control Bonds	$ 50,000	Variable	2014
Pollution Control Bonds	50,000	Variable	2014
Pollution Control Bonds	65,000	Variable	2036
Senior Unsecured Notes	250,000	5.75	2013

Retirements and Principal Payments

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
	(in thousands)	(%)	
Notes Payable – Nonaffiliated	$ 1,463	6.81	2008
Notes Payable – Nonaffiliated	12,000	6.27	2009
Pollution Control Bonds	50,000	Variable	2014
Pollution Control Bonds	50,000	Variable	2016
Pollution Control Bonds	50,000	Variable	2022
Pollution Control Bonds	35,000	Variable	2022
Pollution Control Bonds	65,000	Variable	2036

Liquidity

In recent months, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting OPCo's access to capital, liquidity and cost of capital. The uncertainties in the credit markets could have significant implications on OPCo since it relies on continuing access to capital to fund operations and capital expenditures.

OPCo participates in the Utility Money Pool, which provides access to AEP's liquidity. OPCo has $37 million of Senior Unsecured Notes that will mature in 2008 and $82 million of Notes Payable that will mature in 2009. To the extent refinancing is unavailable due to challenging credit markets, OPCo will rely upon cash flows from operations and access to the Utility Money Pool to fund its maturities, current operations and capital expenditures.

Summary Obligation Information

A summary of contractual obligations is included in the 2007 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" and "Financing Activity" above and letters of credit. In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. As of September 30, 2008, $167 million of letters of credit were issued by OPCo under the 3-year credit agreement to support variable rate demand notes.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2007 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page H-1. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for additional discussion of relevant factors.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2007 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on OPCo.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in OPCo's Condensed Consolidated Balance sheet as of September 30, 2008 and the reasons for changes in total MTM value as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet As of September 30, 2008 (in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 77,357	$ 2,245	$ -	$ (2,466)	$ 77,136
Noncurrent Assets	48,369	720	-	(3,281)	45,808
Total MTM Derivative Contract Assets	125,726	2,965	-	(5,747)	122,944
Current Liabilities	(67,432)	(3,170)	(2,174)	620	(72,156)
Noncurrent Liabilities	(24,105)	-	(2,222)	36	(26,291)
Total MTM Derivative Contract Liabilities	(91,537)	(3,170)	(4,396)	656	(98,447)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 34,189	$ (205)	$ (4,396)	$ (5,091)	$ 24,497

(a) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2008
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2007	$	30,248
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(8,565)
Fair Value of New Contracts at Inception When Entered During the Period (a)		1,154
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		(64)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)		1,026
Changes in Fair Value Due to Market Fluctuations During the Period (c)		13,061
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		(2,671)
Total MTM Risk Management Contract Net Assets		34,189
Net Cash Flow & Fair Value Hedge Contracts		(205)
DETM Assignment (e)		(4,396)
Collateral Deposits		(5,091)
Ending Net Risk Management Assets at September 30, 2008	$	24,497

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.
(e) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

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

The following table presents the maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash:

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of September 30, 2008
(in thousands)

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ (695)	$ (1,596)	$ (15)	$ -	$ -	$ -	$ (2,306)
Level 2 (b)	310	16,487	12,052	724	338	-	29,911
Level 3 (c)	(2,788)	462	(1,303)	189	107	-	(3,333)
Total	(3,173)	15,353	10,734	913	445	-	24,272
Dedesignated Risk Management Contracts (d)	976	3,282	3,256	1,268	1,135	-	9,917
Total MTM Risk Management Contract Net Assets (Liabilities)	$ (2,197)	$ 18,635	$ 13,990	$ 2,181	$ 1,580	$ -	$ 34,189

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.
(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.
(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.
(d) Dedesignated Risk Management Contracts are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized into Revenues over the remaining life of the contract.

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

OPCo is exposed to market fluctuations in energy commodity prices impacting power operations. Management monitors these risks on future operations and may use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. Management does not hedge all commodity price risk.

Management uses interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate risk.

Management uses foreign currency derivatives to lock in prices on certain forecasted transactions denominated in foreign currencies where deemed necessary, and designates qualifying instruments as cash flow hedges. Management does not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on OPCo's Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2007 to September 30, 2008. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2008
(in thousands)

	Power	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2007	$ (756)	$ 2,167	$ (254)	$ 1,157
Changes in Fair Value	431	(903)	68	(404)
Reclassifications from AOCI for Cash Flow Hedges Settled	859	160	10	1,029
Ending Balance in AOCI September 30, 2008	$ 534	$ 1,424	$ (176)	$ 1,782

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $328 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at September 30, 2008, a near term typical change in commodity prices is not expected to have a material effect on OPCo's 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 periods indicated:

Nine Months Ended September 30, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$901	$1,284	$447	$132	$325	$2,054	$490	$90

Management back-tests its VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Management's backtesting results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes OPCo's VaR calculation is conservative.

As OPCo's VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand its exposure to extreme price moves. Management employs a historically-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translate into the largest potential mark-to-market loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which OPCo'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. The estimated EaR on OPCo's debt portfolio was $10.1 million.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2008	**2007**	**2008**	**2007**
REVENUES				
Electric Generation, Transmission and Distribution	$ 600,841	$ 543,404	$ 1,672,203	$ 1,516,383
Sales to AEP Affiliates	245,830	205,193	739,077	564,292
Other - Affiliated	5,759	5,749	17,545	16,604
Other - Nonaffiliated	4,584	3,397	12,738	10,838
TOTAL	857,014	757,743	2,441,563	2,108,117
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	359,341	254,310	928,465	653,941
Purchased Electricity for Resale	56,142	33,178	129,874	85,900
Purchased Electricity from AEP Affiliates	48,867	43,147	116,540	92,858
Other Operation	98,653	102,850	280,494	292,809
Maintenance	51,791	45,663	159,706	155,428
Depreciation and Amortization	72,180	84,400	211,919	253,455
Taxes Other Than Income Taxes	49,019	47,506	146,534	146,211
TOTAL	735,993	611,054	1,973,532	1,680,602
OPERATING INCOME	121,021	146,689	468,031	427,515
Other Income (Expense):				
Interest Income	2,252	108	6,910	992
Carrying Costs Income	3,936	3,644	12,159	10,779
Allowance for Equity Funds Used During Construction	555	590	1,801	1,607
Interest Expense	(39,964)	(36,262)	(116,199)	(95,927)
INCOME BEFORE INCOME TAX EXPENSE	87,800	114,769	372,702	344,966
Income Tax Expense	31,601	39,507	125,782	116,103
NET INCOME	56,199	75,262	246,920	228,863
Preferred Stock Dividend Requirements	183	183	549	549
EARNINGS APPLICABLE TO COMMON STOCK	$ 56,016	$ 75,079	$ 246,371	$ 228,314

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 321,201	$ 536,639	$ 1,207,265	$ (56,763)	$ 2,008,342
FIN 48 Adoption, Net of Tax			(5,380)		(5,380)
Preferred Stock Dividends			(549)		(549)
TOTAL					2,002,413
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,878				(3,486)	(3,486)
NET INCOME			228,863		228,863
TOTAL COMPREHENSIVE INCOME					225,377
SEPTEMBER 30, 2007	$ 321,201	$ 536,639	$ 1,430,199	$ (60,249)	$ 2,227,790
DECEMBER 31, 2007	$ 321,201	$ 536,640	$ 1,469,717	$ (36,541)	$ 2,291,017
EITF 06-10 Adoption, Net of Tax of $1,004			(1,864)		(1,864)
SFAS 157 Adoption, Net of Tax of $152			(282)		(282)
Preferred Stock Dividends			(549)		(549)
TOTAL					2,288,322
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $337				625	625
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,136				2,110	2,110
NET INCOME			246,920		246,920
TOTAL COMPREHENSIVE INCOME					249,655
SEPTEMBER 30, 2008	$ 321,201	$ 536,640	$ 1,713,942	$ (33,806)	$ 2,537,977

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 9,088	$ 6,666
Advances to Affiliates	39,758	-
Accounts Receivable:		
Customers	93,951	104,783
Affiliated Companies	105,503	119,560
Accrued Unbilled Revenues	24,947	26,819
Miscellaneous	11,551	1,578
Allowance for Uncollectible Accounts	(3,555)	(3,396)
Total Accounts Receivable	232,397	249,344
Fuel	146,332	92,874
Materials and Supplies	104,924	108,447
Risk Management Assets	77,136	44,236
Prepayments and Other	38,372	18,300
TOTAL	648,007	519,867
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	5,937,723	5,641,537
Transmission	1,101,463	1,068,387
Distribution	1,442,047	1,394,988
Other	379,242	318,805
Construction Work in Progress	683,404	716,640
Total	9,543,879	9,140,357
Accumulated Depreciation and Amortization	3,084,683	2,967,285
TOTAL - NET	6,459,196	6,173,072
OTHER NONCURRENT ASSETS		
Regulatory Assets	324,260	323,105
Long-term Risk Management Assets	45,808	49,586
Deferred Charges and Other	207,562	272,799
TOTAL	577,630	645,490
TOTAL ASSETS	$ 7,684,833	$ 7,338,429

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2008 and December 31, 2007
(Unaudited)

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 101,548
Accounts Payable:		
General	187,803	141,196
Affiliated Companies	132,195	137,389
Short-term Debt – Nonaffiliated	-	701
Long-term Debt Due Within One Year – Nonaffiliated	119,225	55,188
Risk Management Liabilities	72,156	40,548
Customer Deposits	24,002	30,613
Accrued Taxes	130,211	185,011
Accrued Interest	37,704	41,880
Other	151,044	149,658
TOTAL	854,340	883,732
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,682,247	2,594,410
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	26,291	32,194
Deferred Income Taxes	957,441	914,170
Regulatory Liabilities and Deferred Investment Tax Credits	150,794	160,721
Deferred Credits and Other	242,084	229,635
TOTAL	4,258,857	4,131,130
TOTAL LIABILITIES	5,113,197	5,014,862
Minority Interest	17,032	15,923
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,627	16,627
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	536,640	536,640
Retained Earnings	1,713,942	1,469,717
Accumulated Other Comprehensive Income (Loss)	(33,806)	(36,541)
TOTAL	2,537,977	2,291,017
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 7,684,833	$ 7,338,429

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 246,920	$ 228,863
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	211,919	253,455
Deferred Income Taxes	45,424	3,938
Carrying Costs Income	(12,159)	(10,779)
Allowance for Equity Funds Used During Construction	(1,801)	(1,607)
Mark-to-Market of Risk Management Contracts	(2,028)	(3,894)
Deferred Property Taxes	63,867	54,036
Change in Other Noncurrent Assets	(52,788)	(20,275)
Change in Other Noncurrent Liabilities	9,300	8,026
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	16,947	(32,723)
Fuel, Materials and Supplies	(48,197)	(1,245)
Accounts Payable	45,252	(59,925)
Accrued Taxes, Net	(56,936)	(19,997)
Other Current Assets	(14,333)	(11,784)
Other Current Liabilities	(17,092)	16,891
Net Cash Flows from Operating Activities	434,295	402,980
INVESTING ACTIVITIES		
Construction Expenditures	(453,405)	(751,161)
Change in Advances to Affiliates, Net	(39,758)	-
Proceeds from Sales of Assets	6,872	7,924
Other	(387)	(23)
Net Cash Flows Used for Investing Activities	(486,678)	(743,260)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	412,389	461,324
Change in Short-term Debt, Net – Nonaffiliated	(701)	895
Change in Advances from Affiliates, Net	(101,548)	(95,940)
Retirement of Long-term Debt – Nonaffiliated	(263,463)	(8,927)
Retirement of Cumulative Preferred Stock	-	(2)
Principal Payments for Capital Lease Obligations	(4,636)	(5,420)
Dividends Paid on Cumulative Preferred Stock	(549)	(549)
Other	13,313	-
Net Cash Flows from Financing Activities	54,805	351,381
Net Increase in Cash and Cash Equivalents	2,422	11,101
Cash and Cash Equivalents at Beginning of Period	6,666	1,625
Cash and Cash Equivalents at End of Period	$ 9,088	$ 12,726
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 112,321	$ 85,851
Net Cash Paid for Income Taxes	61,051	61,459
Noncash Acquisitions Under Capital Leases	2,018	1,620
Noncash Acquisition of Coal Land Rights	41,600	-
Construction Expenditures Included in Accounts Payable at September 30,	25,839	42,055

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

OHIO POWER COMPANY CONSOLIDATED
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to OPCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo. The footnotes begin on page H-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

Results of Operations

Third Quarter of 2008 Compared to Third Quarter of 2007

Reconciliation of Third Quarter of 2007 to Third Quarter of 2008
Net Income
(in millions)

Third Quarter of 2007		$	37
Changes in Gross Margin:			
Retail and Off-system Sales Margins	(6)		
Transmission Revenues	3		
Total Change in Gross Margin			(3)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(11)		
Depreciation and Amortization	(3)		
Taxes Other Than Income Taxes	2		
Other Income	(1)		
Carrying Costs Income	3		
Interest Expense	(1)		
Total Change in Operating Expenses and Other			(11)
Income Tax Expense			5
Third Quarter of 2008		$	28

Net Income decreased $9 million to $28 million in 2008. The key drivers of the decrease were an $11 million increase in Operating Expenses and Other and a $3 million decrease in Gross Margin, offset by a $5 million decrease in Income Tax Expense.

The major components of the decrease 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 and Off-system Sales Margins decreased $6 million primarily due to a decrease in retail sales margins mainly due to an 11% decrease in cooling degree days, partially offset by base rate adjustments.
- Transmission Revenues increased $3 million primarily due to higher rates within SPP.

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

- Other Operation and Maintenance expenses increased $11 million primarily due to:
  - A $4 million increase primarily associated with employee-related expenses.
  - A $2 million increase in overhead line expenses.
  - A $1 million increase in transmission expense primarily due to higher rates within SPP.
  - A $1 million increase in expense for the June 2008 storms.
- Depreciation and Amortization expenses increased $3 million primarily due to an increase in the amortization of the Lawton Settlement regulatory assets.
- Taxes Other Than Income Taxes decreased $2 million primarily due to decreases in real property tax and decreases in state sales and use tax.
- Carrying Costs Income increased $3 million primarily due to the new peaking units and to deferred ice storms costs. See "Oklahoma 2007 Ice Storms" section of Note 3.
- Income Tax Expense decreased $5 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Reconciliation of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2008
Net Income
(in millions)

Nine Months Ended September 30, 2007		$	22
Changes in Gross Margin:			
Retail and Off-system Sales Margins	16		
Transmission Revenues	7		
Other	11		
Total Change in Gross Margin			34
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(24)		
Deferral of Ice Storm Costs	72		
Depreciation and Amortization	(8)		
Taxes Other Than Income Taxes	1		
Other Income	2		
Carrying Costs Income	7		
Interest Expense	(7)		
Total Change in Operating Expenses and Other			43
Income Tax Expense			(30)
Nine Months Ended September 30, 2008		$	69

Net Income increased $47 million to $69 million in 2008. The key drivers of the increase were a $43 million decrease in Operating Expenses and Other and a $34 million increase in Gross Margin, offset by a $30 million increase in Income Tax Expense.

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 and Off-system Sales Margins increased $16 million primarily due to an increase in retail sales margins resulting from base rate adjustments during the year, partially offset by a 5% decrease in cooling degree days.
- Transmission Revenues increased $7 million primarily due to higher rates within SPP.
- Other revenues increased $11 million primarily due to an increase related to the recognition of the sale of SO_2 allowances. See “Oklahoma 2007 Ice Storms” section of Note 3.

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

- Other Operation and Maintenance expenses increased $24 million primarily due to:
  - A $12 million increase in production expenses primarily due to a $10 million write-off of pre-construction costs related to the cancelled Red Rock Generating Facility. See "Red Rock Generating Facility" section of Note 3.
  - A $10 million increase due to amortization of the deferred 2007 ice storm costs.
  - A $7 million increase in transmission expense primarily due to higher rates within SPP.
  - A $6 million increase in administrative and general expenses, primarily associated with outside services and employee-related expenses.
  - A $3 million increase in expense for the June 2008 storms.
  - A $2 million increase in distribution maintenance expense due to increased vegetation management activities.

  These increases were partially offset by:
  - A $12 million decrease for the costs of the January 2007 ice storm.
  - A $10 million decrease primarily to true-up actual December ice storm costs to the 2007 estimated accrual.
- Deferral of Ice Storm Costs in 2008 of $72 million results from an OCC order approving recovery of ice storm costs related to ice storms in January and December 2007. See "Oklahoma 2007 Ice Storms" section of Note 3.
- Depreciation and Amortization expenses increased $8 million primarily due to an increase related to the amortization of the Lawton Settlement regulatory assets.
- Other Income increased $2 million primarily due to an increase in the equity component of AFUDC.
- Carrying Costs Income increased $7 million due to the new peaking units and deferred ice storm costs. See "Oklahoma 2007 Ice Storms" section of Note 3.
- Interest Expense increased $7 million primarily due to a $12 million increase in interest expense from long-term borrowings, partially offset by a $4 million decrease in interest expense from short-term borrowings.
- Income Tax Expense increased $30 million primarily due to an increase in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have PSO on stable outlook. In the first quarter of 2008, Fitch downgraded PSO from A- to BBB+ for senior unsecured debt. Current credit ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa1	BBB	BBB+

If PSO receives an upgrade from any of the rating agencies listed above, its borrowing costs could decrease. If PSO receives a downgrade from any of the rating agencies listed above, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the nine months ended September 30, 2008 and 2007 were as follows:

	2008	2007
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,370	$ 1,651
Cash Flows from (Used for):		
Operating Activities	42,386	62,042
Investing Activities	(161,523)	(231,916)
Financing Activities	120,011	169,713
Net Increase (Decrease) in Cash and Cash Equivalents	874	(161)
Cash and Cash Equivalents at End of Period	$ 2,244	$ 1,490

Operating Activities

Net Cash Flows from Operating Activities were $42 million in 2008. PSO produced Net Income of $69 million during the period and had noncash expense items of $78 million for Depreciation and Amortization and $71 million for Deferred Income Taxes. PSO established a $72 million regulatory asset for an OCC order approving recovery of ice storm costs related to storms in January and December 2007. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $81 million outflow from Accounts Payable was primarily due to a decrease in accounts payable accruals and purchased power payable. The $47 million outflow from Fuel Over/Under-Recovery, Net resulted from rapidly increasing natural gas costs which fuels the majority of PSO's generating facilities. The $36 million inflow from Accrued Taxes, Net was the result of a refund for the 2007 overpayment of federal income taxes and increased accruals related to property and income taxes.

Net Cash Flows from Operating Activities were $62 million in 2007. PSO produced Net Income of $22 million during the period and had a noncash expense item of $70 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $32 million outflow from Accounts Receivable, Net was primarily due to a receivable booked on behalf of the joint owners of a generating station related to fuel transportation costs. The $26 million inflow from Margin Deposits was primarily due to gas trading activities. The $8 million outflow from Fuel Over/Under Recovery, Net resulted from increasing natural gas costs which fuels the majority of PSO's generating facilities.

Investing Activities

Net Cash Flows Used for Investing Activities during 2008 and 2007 were $162 million and $232 million, respectively. Construction Expenditures of $214 million and $235 million in 2008 and 2007, respectively, were primarily related to projects for improved generation, transmission and distribution service reliability. In addition, during 2008, PSO had a net decrease of $51 million in loans to the Utility Money Pool. For the remainder of 2008, PSO expects construction expenditures to be approximately $70 million.

Financing Activities

Net Cash Flows from Financing Activities were $120 million during 2008. PSO had a net increase of $125 million in borrowings from the Utility Money Pool. PSO repurchased $34 million in Pollution Control Bonds in May 2008. PSO received capital contributions from the Parent of $30 million.

Net Cash Flows from Financing Activities were $170 million during 2007. PSO had a net increase of $111 million in borrowings from the Utility Money Pool. PSO received capital contributions from the Parent of $60 million.

Financing Activity

Long-term debt issuances, retirements and principal payments made during the first nine months of 2008 were:

Issuances

None

Retirements and Principal Payments

Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Pollution Control Bonds	$ 33,700	Variable	2014

Liquidity

In recent months, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting PSO's access to capital, liquidity and cost of capital. The uncertainties in the credit markets could have significant implications on PSO since it relies on continuing access to capital to fund operations and capital expenditures.

PSO participates in the Utility Money Pool, which provides access to AEP's liquidity. PSO has $50 million of Senior Unsecured Notes that will mature in 2009. To the extent refinancing is unavailable due to the challenging credit markets, PSO will rely upon cash flows from operations and access to the Utility Money Pool to fund its maturity, current operations and capital expenditures.

Summary Obligation Information

The summary of contractual obligations for the year ended 2007 is included in the second quarter 2008 10-Q and has not changed significantly other than the debt retirement discussed in "Cash Flow" and "Financing Activity" above.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, PSO is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2007 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page H-1. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for additional discussion of relevant factors.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2007 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on PSO.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in PSO's Condensed Balance Sheet as of September 30, 2008 and the reasons for changes in total MTM value as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to
Condensed Balance Sheet
As of September 30, 2008
(in thousands)

	MTM Risk Management Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 25,165	$ -	$ (448)	$ 24,717
Noncurrent Assets	2,703	-	(51)	2,652
Total MTM Derivative Contract Assets	27,868	-	(499)	27,369
Current Liabilities	(25,508)	(110)	40	(25,578)
Noncurrent Liabilities	(1,891)	(112)	7	(1,996)
Total MTM Derivative Contract Liabilities	(27,399)	(222)	47	(27,574)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 469	$ (222)	$ (452)	$ (205)

(a) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2008
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2007	$	6,981
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(6,988)
Fair Value of New Contracts at Inception When Entered During the Period (a)		-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)		20
Changes in Fair Value Due to Market Fluctuations During the Period (c)		(104)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		560
Total MTM Risk Management Contract Net Assets		469
DETM Assignment (e)		(222)
Collateral Deposits		(452)
Ending Net Risk Management Assets (Liabilities) at September 30, 2008	$	(205)

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.
(e) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

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

The following table presents the maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash:

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of September 30, 2008
(in thousands)

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ 316	$ (250)	$ -	$ -	$ -	$ -	$ 66
Level 2 (b)	50	1,134	511	(85)	-	-	1,610
Level 3 (c)	(1,208)	-	1	-	-	-	(1,207)
Total	$ (842)	$ 884	$ 512	$ (85)	$ -	$ -	$ 469

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.
(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.
(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

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

Management uses interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on PSO's Condensed Balance Sheets and the reasons for the changes from December 31, 2007 to September 30, 2008. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2008
(in thousands)

	Interest Rate
Beginning Balance in AOCI December 31, 2007	$ (887)
Changes in Fair Value	-
Reclassifications from AOCI for Cash Flow Hedges Settled	137
Ending Balance in AOCI September 30, 2008	$ (750)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $183 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at September 30, 2008, a near term typical change in commodity prices is not expected to have a material effect on PSO's 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 periods indicated:

Nine Months Ended September 30, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$69	$164	$45	$8	$13	$189	$53	$5

Management back-tests its 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. Management's backtesting results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes PSO's VaR calculation is conservative.

As PSO's VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand PSO's exposure to extreme price moves. Management employs a historically-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translate into the largest potential mark-to-market loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which PSO'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. The estimated EaR on PSO's debt portfolio was $3.6 million.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2008	**2007**	**2008**	**2007**
REVENUES				
Electric Generation, Transmission and Distribution	$ 518,182	$ 433,737	$ 1,194,737	$ 1,028,637
Sales to AEP Affiliates	32,286	12,737	89,988	53,605
Other	781	1,562	2,858	2,746
TOTAL	551,249	448,036	1,287,583	1,084,988
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	288,027	182,680	584,769	438,828
Purchased Electricity for Resale	77,834	75,875	230,432	213,429
Purchased Electricity from AEP Affiliates	15,169	16,216	53,944	48,679
Other Operation	51,432	44,030	152,617	127,382
Maintenance	27,530	24,128	87,772	89,390
Deferral of Ice Storm Costs	69	-	(71,610)	-
Depreciation and Amortization	27,192	24,430	78,079	70,128
Taxes Other Than Income Taxes	7,839	10,007	29,265	30,191
TOTAL	495,092	377,366	1,145,268	1,018,027
OPERATING INCOME	56,157	70,670	142,315	66,961
Other Income (Expense):				
Other Income	34	1,086	4,004	2,294
Carrying Costs Income	3,183	-	6,945	-
Interest Expense	(13,713)	(12,381)	(43,179)	(36,549)
INCOME BEFORE INCOME TAX EXPENSE	45,661	59,375	110,085	32,706
Income Tax Expense	17,917	22,804	40,815	10,266
NET INCOME	27,744	36,571	69,270	22,440
Preferred Stock Dividend Requirements	53	53	159	159
EARNINGS APPLICABLE TO COMMON STOCK	$ 27,691	$ 36,518	$ 69,111	$ 22,281

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 157,230	$ 230,016	$ 199,262	$ (1,070)	$ 585,438
FIN 48 Adoption, Net of Tax			(386)		(386)
Capital Contribution from Parent		60,000			60,000
Preferred Stock Dividends			(159)		(159)
TOTAL					644,893
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $74				137	137
NET INCOME			22,440		22,440
TOTAL COMPREHENSIVE INCOME					22,577
SEPTEMBER 30, 2007	$ 157,230	$ 290,016	$ 221,157	$ (933)	$ 667,470
DECEMBER 31, 2007	$ 157,230	$ 310,016	$ 174,539	$ (887)	$ 640,898
EITF 06-10 Adoption, Net of Tax of $596			(1,107)		(1,107)
Capital Contribution from Parent		30,000			30,000
Preferred Stock Dividends			(159)		(159)
TOTAL					669,632
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $74				137	137
NET INCOME			69,270		69,270
TOTAL COMPREHENSIVE INCOME					69,407
SEPTEMBER 30, 2008	$ 157,230	$ 340,016	$ 242,543	$ (750)	$ 739,039

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,244	$ 1,370
Advances to Affiliates	-	51,202
Accounts Receivable:		
Customers	42,023	74,330
Affiliated Companies	72,627	59,835
Miscellaneous	9,716	10,315
Allowance for Uncollectible Accounts	(28)	-
Total Accounts Receivable	124,338	144,480
Fuel	26,547	19,394
Materials and Supplies	47,419	47,691
Risk Management Assets	24,717	33,308
Accrued Tax Benefits	13,040	31,756
Regulatory Asset for Under-Recovered Fuel Costs	35,495	-
Margin Deposits	426	8,980
Prepayments and Other	18,385	18,137
TOTAL	292,611	356,318
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,252,804	1,110,657
Transmission	601,518	569,746
Distribution	1,437,156	1,337,038
Other	253,886	241,722
Construction Work in Progress	77,392	200,018
Total	3,622,756	3,459,181
Accumulated Depreciation and Amortization	1,191,777	1,182,171
TOTAL - NET	2,430,979	2,277,010
OTHER NONCURRENT ASSETS		
Regulatory Assets	186,216	158,731
Long-term Risk Management Assets	2,652	3,358
Deferred Charges and Other	59,369	48,454
TOTAL	248,237	210,543
TOTAL ASSETS	$ 2,971,827	$ 2,843,871

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2008 and December 31, 2007
(Unaudited)

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 125,029	$ -
Accounts Payable:		
General	98,541	189,032
Affiliated Companies	74,420	80,316
Long-term Debt Due Within One Year – Nonaffiliated	50,000	-
Risk Management Liabilities	25,578	27,118
Customer Deposits	39,498	41,477
Accrued Taxes	35,282	18,374
Regulatory Liability for Over-Recovered Fuel Costs	-	11,697
Other	46,703	57,708
TOTAL	495,051	425,722
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	834,798	918,316
Long-term Risk Management Liabilities	1,996	2,808
Deferred Income Taxes	530,293	456,497
Regulatory Liabilities and Deferred Investment Tax Credits	316,521	338,788
Deferred Credits and Other	48,867	55,580
TOTAL	1,732,475	1,771,989
TOTAL LIABILITIES	2,227,526	2,197,711
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,262
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $15 Par Value Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	340,016	310,016
Retained Earnings	242,543	174,539
Accumulated Other Comprehensive Income (Loss)	(750)	(887)
TOTAL	739,039	640,898
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,971,827	$ 2,843,871

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 69,270	$ 22,440
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	78,079	70,128
Deferred Income Taxes	70,856	23,220
Deferral of Ice Storm Costs	(71,610)	-
Allowance for Equity Funds Used During Construction	(1,840)	(649)
Mark-to-Market of Risk Management Contracts	6,973	7,120
Change in Other Noncurrent Assets	9,920	(17,754)
Change in Other Noncurrent Liabilities	(34,426)	(31,165)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	21,846	(31,617)
Fuel, Materials and Supplies	(6,881)	(2,110)
Margin Deposits	8,554	26,461
Accounts Payable	(81,228)	10,226
Accrued Taxes, Net	35,624	19,725
Fuel Over/Under-Recovery, Net	(47,192)	(8,260)
Other Current Assets	(1,676)	177
Other Current Liabilities	(13,883)	(25,900)
Net Cash Flows from Operating Activities	42,386	62,042
INVESTING ACTIVITIES		
Construction Expenditures	(214,319)	(235,089)
Change in Advances to Affiliates, Net	51,202	-
Other	1,594	3,173
Net Cash Flows Used for Investing Activities	(161,523)	(231,916)
FINANCING ACTIVITIES		
Capital Contribution from Parent	30,000	60,000
Issuance of Long-term Debt – Nonaffiliated	-	12,488
Change in Advances from Affiliates, Net	125,029	111,169
Retirement of Long-term Debt – Affiliated	(33,700)	(12,660)
Principal Payments for Capital Lease Obligations	(1,159)	(1,125)
Dividends Paid on Cumulative Preferred Stock	(159)	(159)
Net Cash Flows from Financing Activities	120,011	169,713
Net Increase (Decrease) in Cash and Cash Equivalents	874	(161)
Cash and Cash Equivalents at Beginning of Period	1,370	1,651
Cash and Cash Equivalents at End of Period	$ 2,244	$ 1,490
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 39,739	$ 34,427
Net Cash Received for Income Taxes	44,559	18,004
Noncash Acquisitions Under Capital Leases	403	600
Construction Expenditures Included in Accounts Payable at September 30,	12,251	16,358

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to PSO's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO. The footnotes begin on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

Results of Operations

Third Quarter of 2008 Compared to Third Quarter of 2007

Reconciliation of Third Quarter of 2007 to Third Quarter of 2008
Net Income
(in millions)

Third Quarter of 2007		$	44
Changes in Gross Margin:			
Retail and Off-system Sales Margins (a)	11		
Transmission Revenues	3		
Other	3		
Total Change in Gross Margin			17
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(15)		
Depreciation and Amortization	(1)		
Taxes Other Than Income Taxes	4		
Other Income	5		
Interest Expense	(7)		
Total Change in Operating Expenses and Other			(14)
Third Quarter of 2008		$	47

(a) Includes firm wholesale sales to municipals and cooperatives.

Net Income increased $3 million to $47 million in 2008. The key drivers of the increase were a $17 million increase in Gross Margin, partially offset by a $14 million increase in Operating Expenses and Other.

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 and Off-system Sales Margins increased $11 million primarily due to an increase in wholesale fuel recovery.
- Transmission Revenues increased $3 million due to higher rates in the SPP region.
- Other revenues increased $3 million primarily due to an increase in revenues from coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, to Cleco Corporation, a nonaffiliated entity. The increase in coal deliveries was the result of planned and forced outages during 2007 at the Dolet Hills Generating Station, which is jointly-owned by SWEPCo and Cleco Corporation. The increased revenue from coal deliveries was offset by a corresponding increase in Other Operation and Maintenance expenses from mining operations as discussed below.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $15 million primarily due to the following:
    - A $14 million increase in distribution expenses primarily due to storm restoration expenses for Hurricanes Ike and Gustav. SWEPCo intends to pursue the recovery of these expenses.
    - A $3 million increase in expense for coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC. The increased expenses for coal deliveries were offset by a corresponding increase in revenues from mining operations as discussed above.
- Taxes Other Than Income Taxes decreased $4 million primarily due to a $3 million decrease in state and local franchise tax from refunds related to prior years.
- Other Income increased $5 million primarily due to higher nonaffiliated interest income resulting from the fuel under-recovery balance, the Texas state franchise refund and the Utility Money Pool.
- Interest Expense increased $7 million primarily due to a $10 million increase related to higher long-term debt outstanding, partially offset by a $3 million increase in the debt component of AFUDC due to new generation projects.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Reconciliation of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2008
Net Income
(in millions)

Nine Months Ended September 30, 2007		$ 55
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	38	
Transmission Revenues	7	
Other	-	
Total Change in Gross Margin		45
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(33)	
Depreciation and Amortization	(5)	
Taxes Other Than Income Taxes	5	
Other Income	8	
Interest Expense	(8)	
Total Change in Operating Expenses and Other		(33)
Income Tax Expense		(1)
Nine Months Ended September 30, 2008		$ 66

(a) Includes firm wholesale sales to municipals and cooperatives.

Net Income increased $11 million to $66 million in 2008. The key drivers of the increase were a $45 million increase in Gross Margin, partially offset by a $33 million increase in Operating Expenses and Other.

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 and Off-system Sales Margins increased $38 million primarily due to higher fuel recovery resulting from an $18 million refund provision booked in 2007 pursuant to an unfavorable ALJ ruling in the Texas Fuel Reconciliation proceeding. In addition, an increase of $10 million in wholesale revenue and lower purchase power capacity of $4 million was reflected in 2008.
- Transmission Revenues increased $7 million due to higher rates in the SPP region.
- While Other revenues in total were unchanged, there was a $12 million decrease in gains on sales of emission allowances. This decrease was offset by an $11 million increase in revenue from coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, to Cleco Corporation, a nonaffiliated entity. The increase in coal deliveries was the result of planned and forced outages during 2007 at the Dolet Hills Generating Station, which is jointly-owned by SWEPCo and Cleco Corporation. The increased revenue from coal deliveries was offset by a corresponding increase in Other Operation and Maintenance expenses from mining operations as discussed below.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $33 million primarily due to the following:
  - A $12 million increase in distribution expenses primarily due to storm restoration expenses from Hurricanes Ike and Gustav. SWEPCo intends to pursue the recovery of these expenses.
  - A $14 million increase in expenses for coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC. The increased expenses for coal deliveries were offset by a corresponding increase in revenues from mining operations as discussed above.
- Depreciation and Amortization increased $5 million primarily due to higher depreciable asset balances.
- Taxes Other Than Income Taxes decreased $5 million primarily due to a decrease in state and local franchise tax from refunds related to prior years.
- Other Income increased $8 million primarily due to higher nonaffiliated interest income and an increase in the equity component of AFUDC as a result of new generation projects.
- Interest Expense increased $8 million primarily due to a $17 million increase from higher long-term debt outstanding, partially offset by a $7 million increase in the debt component of AFUDC due to new generation projects.
- Income Tax Expense increased $1 million primarily due to an increase in pretax book income, partially offset by state income taxes and changes in certain book/tax differences accounted for on a flow-through basis.

Financial Condition

Credit Ratings

S&P and Fitch currently have SWEPCo on stable outlook, while Moody's placed SWEPCo on negative outlook in the first quarter of 2008. In addition, in the first quarter of 2008, Fitch downgraded SWEPCo from A- to BBB+ for senior unsecured debt. Current credit ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa1	BBB	BBB+

If SWEPCo receives an upgrade from any of the rating agencies listed above, its borrowing costs could decrease. If SWEPCo receives a downgrade from any of the rating agencies listed above, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the nine months ended September 30, 2008 and 2007 were as follows:

	2008	2007
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,742	$ 2,618
Cash Flows from (Used for):		
Operating Activities	130,250	180,146
Investing Activities	(619,487)	(353,001)
Financing Activities	490,247	172,089
Net Increase (Decrease) in Cash and Cash Equivalents	1,010	(766)
Cash and Cash Equivalents at End of Period	$ 2,752	$ 1,852

Operating Activities

Net Cash Flows from Operating Activities were $130 million in 2008. SWEPCo produced Net Income of $66 million during the period and had a noncash expense item of $109 million for Depreciation and Amortization and $37 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $99 million outflow from Fuel Over/Under-Recovery, Net was the result of higher fuel costs. The $47 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company. The $35 million outflow from Accounts Payable was primarily due to a decrease in purchased power payables. The $29 million inflow from Accrued Taxes, Net was due to a refund for the 2007 overpayment of federal income taxes.

Net Cash Flows from Operating Activities were $180 million in 2007. SWEPCo produced Net Income of $55 million during the period and had noncash expense items of $103 million for Depreciation and Amortization and $24 million related to the Provision for Fuel Disallowance recorded as the result of an ALJ ruling in SWEPCo's Texas fuel reconciliation proceeding. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $48 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company. The $30 million inflow from Margin Deposits was due to decreased trading-related deposits resulting from normal trading activities. The $27 million outflow from Fuel Over/Under Recovery, Net is due to under recovery of higher fuel costs.

Investing Activities

Net Cash Flows Used for Investing Activities during 2008 and 2007 were $619 million and $353 million, respectively. Construction Expenditures of $424 million and $353 million in 2008 and 2007, respectively, were primarily related to new generation projects at the Turk Plant, Mattison Plant and Stall Unit. In addition, during 2008, SWEPCo had a net increase of $196 million in loans to the Utility Money Pool. For the remainder of 2008, SWEPCo expects construction expenditures to be approximately $250 million.

Financing Activities

Net Cash Flows from Financing Activities were $490 million during 2008. SWEPCo issued $400 million of Senior Unsecured Notes. SWEPCo received a Capital Contribution from Parent of $100 million. SWEPCo retired $46 million of Nonaffiliated Long-term Debt.

Net Cash Flows from Financing Activities were $172 million during 2007. SWEPCo issued $250 million of Senior Unsecured Notes and retired $90 million of First Mortgage Bonds. SWEPCo received a Capital Contribution from Parent of $55 million. SWEPCo also reduced its borrowings from the Utility Money Pool by $33 million.

Financing Activity

Long-term debt issuances, retirements and principal payments made during the first nine months of 2008 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 400,000	6.45	2019
Pollution Control Bonds	41,135	4.50	2011

Retirements and Principal Payments

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
	(in thousands)	(%)	
Notes Payable – Nonaffiliated	$ 1,500	Variable	2008
Notes Payable – Nonaffiliated	3,304	4.47	2011
Pollution Control Bonds	41,135	Variable	2011

In October 2008, SWEPCo retired $113 million of 5.25% Notes Payable due in 2043.

Liquidity

In recent months, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting SWEPCo's access to capital, liquidity and cost of capital. The uncertainties in the credit markets could have significant implications on SWEPCo since it relies on continuing access to capital to fund operations and capital expenditures.

SWEPCo participates in the Utility Money Pool, which provides access to AEP's liquidity. SWEPCo has no debt obligations that will mature in the remainder of 2008 or 2009. To the extent refinancing is unavailable due to the challenging credit markets, SWEPCo will rely upon cash flows from operations and access to the Utility Money Pool to fund its current operations.

Summary Obligation Information

A summary of contractual obligations is included in the 2007 Annual Report and has not changed significantly from year-end other than the debt issuance discussed in "Cash Flow" and "Financing Activity" above.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2007 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page H-1. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for additional discussion of relevant factors.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2007 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on SWEPCo.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in SWEPCo's Condensed Consolidated Balance Sheet as of September 30, 2008 and the reasons for changes in total MTM value as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of September 30, 2008
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 30,804	$ -	$ -	$ (528)	$ 30,276
Noncurrent Assets	3,561	-	-	(60)	3,501
Total MTM Derivative Contract Assets	34,365	-	-	(588)	33,777
Current Liabilities	(31,197)	(90)	(130)	60	(31,357)
Noncurrent Liabilities	(2,406)	(93)	(132)	9	(2,622)
Total MTM Derivative Contract Liabilities	(33,603)	(183)	(262)	69	(33,979)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 762	$ (183)	$ (262)	$ (519)	$ (202)

(a) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2008
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2007	$	8,131
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(8,169)
Fair Value of New Contracts at Inception When Entered During the Period (a)		-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)		103
Changes in Fair Value Due to Market Fluctuations During the Period (c)		106
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		591
Total MTM Risk Management Contract Net Assets		762
Net Cash Flow & Fair Value Hedge Contracts		(183)
DETM Assignment (e)		(262)
Collateral Deposits		(519)
Ending Net Risk Management Assets (Liabilities) at September 30, 2008	$	(202)

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.
(e) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

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

The following table presents the maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash:

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of September 30, 2008
(in thousands)

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ 372	$ (294)	$ -	$ -	$ -	$ -	$ 78
Level 2 (b)	10	1,467	757	(122)	-	-	2,112
Level 3 (c)	(1,429)	-	1	-	-	-	(1,428)
Total	$ (1,047)	$ 1,173	$ 758	$ (122)	$ -	$ -	$ 762

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.
(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.
(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

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

Management uses interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate risk.

Management uses foreign currency derivatives to lock in prices on certain forecasted transactions denominated in foreign currencies where deemed necessary, and designates qualifying instruments as cash flow hedges. Management does not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on SWEPCo's Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2007 to September 30, 2008. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2008
(in thousands)

	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2007	$ (6,650)	$ 629	$ (6,021)
Changes in Fair Value	-	(204)	(204)
Reclassifications from AOCI for Cash Flow Hedges Settled	621	(544)	77
Ending Balance in AOCI September 30, 2008	$ (6,029)	$ (119)	$ (6,148)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $829 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at September 30, 2008, a near term typical change in commodity prices is not expected to have a material effect on SWEPCo's 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 periods indicated:

Nine Months Ended September 30, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$101	$220	$64	$11	$17	$245	$75	$7

Management back-tests its 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. Management's backtesting results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes SWEPCo's VaR calculation is conservative.

As SWEPCo's VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand SWEPCo's exposure to extreme price moves. Management employs a historically-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translate into the largest potential mark-to-market loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which SWEPCo'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. The estimated EaR on SWEPCo's debt portfolio was $1.9 million.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended 2008	Three Months Ended 2007	Nine Months Ended 2008	Nine Months Ended 2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 500,484	$ 445,169	$ 1,232,017	$ 1,101,703
Sales to AEP Affiliates	11,508	2,839	42,692	35,491
Other	471	502	1,164	1,437
TOTAL	512,463	448,510	1,275,873	1,138,631
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	197,474	141,837	462,282	379,818
Purchased Electricity for Resale	50,449	73,438	145,097	182,806
Purchased Electricity from AEP Affiliates	36,170	22,282	108,542	61,284
Other Operation	64,377	59,759	186,713	163,746
Maintenance	33,694	23,205	88,854	79,265
Depreciation and Amortization	35,842	34,605	108,875	103,395
Taxes Other Than Income Taxes	12,623	16,767	45,747	50,298
TOTAL	430,629	371,893	1,146,110	1,020,612
OPERATING INCOME	81,834	76,617	129,763	118,019
Other Income (Expense):				
Interest Income	5,417	518	7,834	1,999
Allowance for Equity Funds Used During Construction	4,152	3,681	10,167	7,634
Interest Expense	(22,659)	(15,966)	(57,071)	(48,691)
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTEREST EXPENSE	68,744	64,850	90,693	78,961
Income Tax Expense	20,353	19,811	21,717	20,879
Minority Interest Expense	976	919	2,870	2,733
NET INCOME	47,415	44,120	66,106	55,349
Preferred Stock Dividend Requirements	58	58	172	172
EARNINGS APPLICABLE TO COMMON STOCK	$ 47,357	$ 44,062	$ 65,934	$ 55,177

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 135,660	$ 245,003	$ 459,338	$ (18,799)	$ 821,202
FIN 48 Adoption, Net of Tax			(1,642)		(1,642)
Capital Contribution from Parent		55,000			55,000
Preferred Stock Dividends			(172)		(172)
TOTAL					874,388
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $90				168	168
NET INCOME			55,349		55,349
TOTAL COMPREHENSIVE INCOME					55,517
SEPTEMBER 30, 2007	$ 135,660	$ 300,003	$ 512,873	$ (18,631)	$ 929,905
DECEMBER 31, 2007	$ 135,660	$ 330,003	$ 523,731	$ (16,439)	$ 972,955
EITF 06-10 Adoption, Net of Tax of $622			(1,156)		(1,156)
SFAS 157 Adoption, Net of Tax of $6			10		10
Capital Contribution from Parent		100,000			100,000
Preferred Stock Dividends			(172)		(172)
TOTAL					1,071,637
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $69				(127)	(127)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $380				706	706
NET INCOME			66,106		66,106
TOTAL COMPREHENSIVE INCOME					66,685
SEPTEMBER 30, 2008	$ 135,660	$ 430,003	$ 588,519	$ (15,860)	$ 1,138,322

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,752	$ 1,742
Advances to Affiliates	195,628	-
Accounts Receivable:		
Customers	32,619	91,379
Affiliated Companies	42,876	33,196
Miscellaneous	12,781	10,544
Allowance for Uncollectible Accounts	(135)	(143)
Total Accounts Receivable	88,141	134,976
Fuel	89,408	75,662
Materials and Supplies	51,565	48,673
Risk Management Assets	30,276	39,850
Regulatory Asset for Under-Recovered Fuel Costs	81,907	5,859
Margin Deposits	600	10,650
Prepayments and Other	38,406	28,147
TOTAL	578,683	345,559
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,756,486	1,743,198
Transmission	771,747	737,975
Distribution	1,364,596	1,312,746
Other	698,764	631,765
Construction Work in Progress	735,226	451,228
Total	5,326,819	4,876,912
Accumulated Depreciation and Amortization	1,996,531	1,939,044
TOTAL - NET	3,330,288	2,937,868
OTHER NONCURRENT ASSETS		
Regulatory Assets	120,858	133,617
Long-term Risk Management Assets	3,501	4,073
Deferred Charges and Other	93,126	67,269
TOTAL	217,485	204,959
TOTAL ASSETS	$ 4,126,456	$ 3,488,386

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2008 and December 31, 2007
(Unaudited)

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 1,565
Accounts Payable:		
General	163,540	152,305
Affiliated Companies	41,010	51,767
Short-term Debt – Nonaffiliated	9,519	285
Long-term Debt Due Within One Year – Nonaffiliated	117,809	5,906
Risk Management Liabilities	31,357	32,629
Customer Deposits	34,989	37,473
Accrued Taxes	60,052	26,494
Regulatory Liability for Over-Recovered Fuel Costs	-	22,879
Other	94,559	76,554
TOTAL	552,835	407,857
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,424,395	1,141,311
Long-term Debt – Affiliated	50,000	50,000
Long-term Risk Management Liabilities	2,622	3,334
Deferred Income Taxes	407,149	361,806
Regulatory Liabilities and Deferred Investment Tax Credits	331,985	334,014
Deferred Credits and Other	214,153	210,725
TOTAL	2,430,304	2,101,190
TOTAL LIABILITIES	2,983,139	2,509,047
Minority Interest	298	1,687
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,697	4,697
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	430,003	330,003
Retained Earnings	588,519	523,731
Accumulated Other Comprehensive Income (Loss)	(15,860)	(16,439)
TOTAL	1,138,322	972,955
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 4,126,456	$ 3,488,386

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 66,106	$ 55,349
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	108,875	103,395
Deferred Income Taxes	37,162	(17,863)
Provision for Fuel Disallowance	-	24,074
Allowance for Equity Funds Used During Construction	(10,167)	(7,634)
Mark-to-Market of Risk Management Contracts	7,905	7,864
Deferred Property Taxes	(9,315)	(9,172)
Change in Other Noncurrent Assets	9,104	10,170
Change in Other Noncurrent Liabilities	(17,015)	(7,134)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	46,835	47,992
Fuel, Materials and Supplies	(16,665)	(11,572)
Margin Deposits	10,050	29,986
Accounts Payable	(34,819)	(21,603)
Accrued Taxes, Net	29,271	25,556
Fuel Over/Under-Recovery, Net	(98,928)	(26,891)
Other Current Assets	(3,121)	(687)
Other Current Liabilities	4,972	(21,684)
Net Cash Flows from Operating Activities	130,250	180,146
INVESTING ACTIVITIES		
Construction Expenditures	(424,092)	(353,107)
Change in Advances to Affiliates, Net	(195,628)	-
Other	233	106
Net Cash Flows Used for Investing Activities	(619,487)	(353,001)
FINANCING ACTIVITIES		
Capital Contribution from Parent	100,000	55,000
Issuance of Long-term Debt – Nonaffiliated	437,113	247,496
Change in Short-term Debt, Net – Nonaffiliated	9,234	8,754
Change in Advances from Affiliates, Net	(1,565)	(33,096)
Retirement of Long-term Debt – Nonaffiliated	(45,939)	(100,460)
Principal Payments for Capital Lease Obligations	(8,424)	(5,433)
Dividends Paid on Cumulative Preferred Stock	(172)	(172)
Net Cash Flows from Financing Activities	490,247	172,089
Net Increase (Decrease) in Cash and Cash Equivalents	1,010	(766)
Cash and Cash Equivalents at Beginning of Period	1,742	2,618
Cash and Cash Equivalents at End of Period	$ 2,752	$ 1,852
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 44,255	$ 44,662
Net Cash Paid (Received) for Income Taxes	(20,835)	37,479
Noncash Acquisitions Under Capital Leases	21,807	19,567
Construction Expenditures Included in Accounts Payable at September 30,	94,837	41,978

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to SWEPCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to SWEPCo. The footnotes begin on page H-1.

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Significant Accounting Matters	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
2.	New Accounting Pronouncements and Extraordinary Item	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
3.	Rate Matters	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
4.	Commitments, Guarantees and Contingencies	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
5.	Acquisition	CSPCo
6.	Benefit Plans	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
7.	Business Segments	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
8.	Income Taxes	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
9.	Financing Activities	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant Subsidiary. The net income for the three and nine months ended September 30, 2008 are not necessarily indicative of results that may be expected for the year ending December 31, 2008. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2007 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K for the year ended December 31, 2007 as filed with the SEC on February 28, 2008.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. See "FSP FIN 39-1 Amendment of FASB Interpretation No. 39" section of Note 2 for discussion of changes in netting certain balance sheet amounts. These reclassifications had no impact on the Registrant Subsidiaries' previously reported net income or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to the Registrant Subsidiaries' business. The following represents a summary of new pronouncements issued or implemented in 2008 and standards issued but not implemented that management has determined relate to the Registrant Subsidiaries' operations.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It establishes how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. SFAS 141R requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period.

SFAS 141R is effective prospectively for business combinations with an acquisition date on or after the beginning of the first annual reporting period after December 15, 2008. Early adoption is prohibited. The Registrant Subsidiaries will adopt SFAS 141R effective January 1, 2009 and apply it to any business combinations on or after that date.

SFAS 157 "Fair Value Measurements" (SFAS 157)

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity includes its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data.

In February 2008, the FASB issued FSP SFAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" (SFAS 157-1) which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" (SFAS 13) and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13.

In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2) which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

In October 2008, the FASB issued FSP SFAS 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active" which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The FSP was effective upon issuance. The adoption of this standard had no impact on the Registrant Subsidiaries' financial statements.

The Registrant Subsidiaries partially adopted SFAS 157 effective January 1, 2008. The Registrant Subsidiaries will fully adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP SFAS 157-2. Management expects that the adoption of FSP SFAS 157-2 will have an immaterial impact on the financial statements. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, APCo, CSPCo and OPCo reduced beginning retained earnings by $440 thousand ($286 thousand, net of tax), $486 thousand ($316 thousand, net of tax) and $434 thousand ($282 thousand, net of tax), respectively, for the transition adjustment. SWEPCo's transition adjustment was a favorable $16 thousand ($10 thousand, net of tax) adjustment to beginning retained earnings. The impact of considering AEP's credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption.

In accordance with SFAS 157, assets and liabilities are classified based on the inputs utilized in the fair value measurement. SFAS 157 provides definitions for two types of inputs: observable and unobservable. Observable inputs are valuation inputs that reflect the assumptions market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the reporting entity. Unobservable inputs are valuation inputs that reflect the reporting entity's own assumptions about the assumptions market participants would use in pricing the asset or liability developed based on the best information in the circumstances.

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 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).

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts, listed equities and U.S. government treasury securities that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 inputs are inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in level 1, OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market and certain non-exchange-traded debt securities.

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

Risk Management Contracts include exchange traded, OTC and bilaterally executed derivative contracts. Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within level 1. Other actively traded derivative fair values are verified using broker or dealer quotations, similar observable market transactions in either the listed or OTC markets, or valued using pricing models where significant valuation inputs are directly or indirectly observable in active markets. Derivative instruments, primarily swaps, forwards, and options that meet these characteristics are classified within level 2. Bilaterally executed agreements are derivative contracts entered into directly with third parties, and at times these instruments may be complex structured transactions that are tailored to meet the specific customer's energy requirements. Structured transactions utilize pricing models that are widely accepted in the energy industry to measure fair value. Generally, management uses a consistent modeling approach to value similar instruments. 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 markets that are not active, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data), and other observable inputs for the asset or liability. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions 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 in level 3. In certain instances, the fair values of the transactions that use internally developed model inputs, classified as level 3 are offset partially or in full, by transactions included in level 2 where observable market data exists for the offsetting transaction.

The following table sets forth, by level within the fair value hierarchy, the Registrant Subsidiaries' financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's 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.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of September 30, 2008

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 7,275	$ 553,289	$ 5,005	$ (447,811)	$ 117,758
Cash Flow and Fair Value Hedges (a)	-	10,120	-	(4,980)	5,140
Dedesignated Risk Management Contracts (b)	-	-	-	14,259	14,259
Total Risk Management Assets	$ 7,275	$ 563,409	$ 5,005	$ (438,532)	$ 137,157
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 10,589	$ 518,486	$ 9,646	$ (440,158)	$ 98,563
Cash Flow and Fair Value Hedges (a)	-	7,976	-	(4,980)	2,996
DETM Assignment (c)	-	-	-	6,321	6,321
Total Risk Management Liabilities	$ 10,589	$ 526,462	$ 9,646	$ (438,817)	$ 107,880

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of September 30, 2008

CSPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (e)	$ 31,002	$ -	$ -	$ 962	$ 31,964
Risk Management Assets:					
Risk Management Contracts (a)	$ 4,083	$ 286,118	$ 2,811	$ (232,301)	$ 60,711
Cash Flow and Fair Value Hedges (a)	-	5,189	-	(2,795)	2,394
Dedesignated Risk Management Contracts (b)	-	-	-	8,005	8,005
Total Risk Management Assets	$ 4,083	$ 291,307	$ 2,811	$ (227,091)	$ 71,110
Total Assets	$ 35,085	$ 291,307	$ 2,811	$ (226,129)	$ 103,074
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 5,945	$ 266,791	$ 5,406	$ (227,981)	$ 50,161
Cash Flow and Fair Value Hedges (a)	-	4,477	-	(2,795)	1,682
DETM Assignment (c)	-	-	-	3,549	3,549
Total Risk Management Liabilities	$ 5,945	$ 271,268	$ 5,406	$ (227,227)	$ 55,392

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of September 30, 2008

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 3,952	$ 283,053	$ 2,721	$ (230,057)	$ 59,669
Cash Flow and Fair Value Hedges (a)	-	5,022	-	(2,705)	2,317
Dedesignated Risk Management Contracts (b)	-	-	-	7,747	7,747
Total Risk Management Assets	$ 3,952	$ 288,075	$ 2,721	$ (225,015)	$ 69,733
Spent Nuclear Fuel and Decommissioning Trusts:					
Cash and Cash Equivalents (d)	$ -	$ 3,523	$ -	$ 6,328	$ 9,851
Debt Securities (f)	-	837,141	-	-	837,141
Equity Securities (g)	444,994	-	-	-	444,994
Total Spent Nuclear Fuel and Decommissioning Trusts	$ 444,994	$ 840,664	$ -	$ 6,328	$ 1,291,986
Total Assets	$ 448,946	$ 1,128,739	$ 2,721	$ (218,687)	$ 1,361,719
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 5,754	$ 264,220	$ 5,234	$ (225,884)	$ 49,324
Cash Flow and Fair Value Hedges (a)	-	4,333	-	(2,705)	1,628
DETM Assignment (c)	-	-	-	3,435	3,435
Total Risk Management Liabilities	$ 5,754	$ 268,553	$ 5,234	$ (225,154)	$ 54,387

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of September 30, 2008

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (e)	$ 3,116	$ -	$ -	$ 2,164	$ 5,280
Risk Management Assets:					
Risk Management Contracts (a)	$ 5,059	$ 582,635	$ 3,476	$ (481,108)	$ 110,062
Cash Flow and Fair Value Hedges (a)	-	6,428	-	(3,463)	2,965
Dedesignated Risk Management Contracts (b)	-	-	-	9,917	9,917
Total Risk Management Assets	$ 5,059	$ 589,063	$ 3,476	$ (474,654)	$ 122,944
Total Assets	$ 8,175	$ 589,063	$ 3,476	$ (472,490)	$ 128,224
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 7,365	$ 552,724	$ 6,809	$ (476,017)	$ 90,881
Cash Flow and Fair Value Hedges (a)	-	6,633	-	(3,463)	3,170
DETM Assignment (c)	-	-	-	4,396	4,396
Total Risk Management Liabilities	$ 7,365	$ 559,357	$ 6,809	$ (475,084)	$ 98,447

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of September 30, 2008

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 3,743	$ 141,674	$ 3,803	$ (121,851)	$ 27,369
Cash Flow and Fair Value Hedges (a)	-	-	-	-	-
Total Risk Management Assets	$ 3,743	$ 141,674	$ 3,803	$ (121,851)	$ 27,369
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 3,677	$ 140,064	$ 5,010	$ (121,399)	$ 27,352
Cash Flow and Fair Value Hedges (a)	-	-	-	-	-
DETM Assignment (c)	-	-	-	222	222
Total Risk Management Liabilities	$ 3,677	$ 140,064	$ 5,010	$ (121,177)	$ 27,574

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of September 30, 2008

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 4,412	$ 177,218	$ 4,481	$ (152,334)	$ 33,777
Cash Flow and Fair Value Hedges (a)	-	44	-	(44)	-
Total Risk Management Assets	$ 4,412	$ 177,262	$ 4,481	$ (152,378)	$ 33,777
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 4,334	$ 175,106	$ 5,909	$ (151,815)	$ 33,534
Cash Flow and Fair Value Hedges (a)	-	227	-	(44)	183
DETM Assignment (c)	-	-	-	262	262
Total Risk Management Liabilities	$ 4,334	$ 175,333	$ 5,909	$ (151,597)	$ 33,979

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized into Utility Operations Revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 16 in the 2007 Annual Report.

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

(e) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.

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

(g) Amounts represent publicly traded equity securities.

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:

Three Months Ended September 30, 2008	**APCo**	**CSPCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in thousands)			
Balance as of July 1, 2008	$ (18,560)	$ (11,122)	$ (10,675)	$ (13,245)	$ (23)	$ (45)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)	4,466	2,670	2,561	3,287	4	13
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	(1,317)	-	(1,574)	-	26
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	5,595	3,360	3,228	3,914	(1,249)	(1,471)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	3,858	3,814	2,373	4,285	61	49
Balance as of September 30, 2008	$ (4,641)	$ (2,595)	$ (2,513)	$ (3,333)	$ (1,207)	$ (1,428)

Nine Months Ended September 30, 2008	**APCo**	**CSPCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in thousands)			
Balance as of January 1, 2008	$ (697)	$ (263)	$ (280)	$ (1,607)	$ (243)	$ (408)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)	332	88	105	1,063	170	290
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	190	-	126	-	56
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	(731)	(454)	(430)	(244)	(1,249)	(1,472)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(3,545)	(2,156)	(1,908)	(2,671)	115	106
Balance as of September 30, 2008	$ (4,641)	$ (2,595)	$ (2,513)	$ (3,333)	$ (1,207)	$ (1,428)

(a) Included in revenues on the Condensed Statements of Income.
(b) "Transfers in and/or out of Level 3" represent 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.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

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

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. The statement is applied prospectively upon adoption.

The Registrant Subsidiaries adopted SFAS 159 effective January 1, 2008. At adoption, the Registrant Subsidiaries did not elect the fair value option for any assets or liabilities.

SFAS 160 “Noncontrolling Interest 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. It 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.

SFAS 160 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. The statement is applied prospectively upon adoption. Early adoption is prohibited. Upon adoption, prior period financial statements will be restated for the presentation of the noncontrolling interest for comparability. Management expects that the adoption of this standard will have an immaterial impact on the financial statements. The Registrant Subsidiaries will adopt SFAS 160 effective January 1, 2009.

SFAS 161 “Disclosures about Derivative Instruments and Hedging Activities” (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. SFAS 161 requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard is intended to improve upon the existing disclosure framework in SFAS 133.

SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008. Management expects this standard to increase the disclosure requirements related to derivative instruments and hedging activities. It encourages retrospective application to comparative disclosure for earlier periods presented. The Registrant Subsidiaries will adopt SFAS 161 effective January 1, 2009.

SFAS 162 “The Hierarchy of Generally Accepted Accounting Principles” (SFAS 162)

In May 2008, the FASB issued SFAS 162, clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP.

SFAS 162 is effective 60 days after the SEC approves the Public Company Accounting Oversight Board’s amendments to AU Section 411, “The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles.” Management expects the adoption of this standard will have no impact on the Registrant Subsidiaries’ financial statements. The Registrant Subsidiaries will adopt SFAS 162 when it becomes effective.

EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements" (EITF 06-10)

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pension" or Accounting Principles Board Opinion No. 12 "Omnibus Opinion – 1967" if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. The Registrant Subsidiaries adopted EITF 06-10 effective January 1, 2008. The impact of this standard was an unfavorable cumulative effect adjustment, net of tax, to beginning retained earnings as follows:

Company	Retained Earnings Reduction	Tax Amount
	(in thousands)	
APCo	$ 2,181	$ 1,175
CSPCo	1,095	589
I&M	1,398	753
OPCo	1,864	1,004
PSO	1,107	596
SWEPCo	1,156	622

EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11)

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after December 15, 2007.

The Registrant Subsidiaries adopted EITF 06-11 effective January 1, 2008. The adoption of this standard had an immaterial impact on the financial statements.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the EITF consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities.

EITF 08-5 is effective for the first reporting beginning period after December 15, 2008. It will be applied prospectively upon adoption with the effect of initial application included as a change in fair value of the liability in the period of adoption. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application. Early adoption is permitted. Although management has not completed an analysis, management expects that the adoption of this standard will have an immaterial impact on the financial statements. The Registrant Subsidiaries will adopt this standard effective January 1, 2009.

FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161" (SFAS 133-1 and FIN 45-4)

In September 2008, the FASB issued SFAS 133-1 and FIN 45-4 as amendments to original statements SFAS 133 and FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Under the SFAS 133 requirements, the seller of a credit derivative shall disclose the following information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote:

(a) The nature of the credit derivative.
(b) The maximum potential amount of future payments.
(c) The fair value of the credit derivative.
(d) The nature of any recourse provisions and any assets held as collateral or by third parties.

Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk.

The standard is effective for interim and annual reporting periods ending after November 15, 2008. Upon adoption, the guidance will be prospectively applied. Management expects that the adoption of this standard will have an immaterial impact on the financial statements but increase the FIN 45 guarantees disclosure requirements. The Registrant Subsidiaries will adopt the standard effective December 31, 2008.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS 142, "Goodwill and Other Intangible Assets." The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

SFAS 142-3 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. Early adoption is prohibited. Upon adoption, the guidance within SFAS 142-3 will be prospectively applied to intangible assets acquired after the effective date. Management expects that the adoption of this standard will have an immaterial impact on the Registrant Subsidiaries' financial statements. The Registrant Subsidiaries will adopt SFAS 142-3 effective January 1, 2009.

FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)

In April 2007, the FASB issued FIN 39-1. It amends FASB Interpretation No. 39 "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to also net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

The Registrant Subsidiaries adopted FIN 39-1 effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. Consequently, the Registrant Subsidiaries reclassified the following amounts on their December 31, 2007 balance sheets as shown:

APCo

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the September 2008 10-Q
Current Assets:		**(in thousands)**	
Risk Management Assets	$ 64,707	$ (1,752)	$ 62,955
Prepayments and Other	19,675	(3,306)	16,369
Long-term Risk Management Assets	74,954	(2,588)	72,366
Current Liabilities:			
Risk Management Liabilities	54,955	(3,247)	51,708
Customer Deposits	50,260	(4,340)	45,920
Long-term Risk Management Liabilities	47,416	(59)	47,357

CSPCo

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the September 2008 10-Q
Current Assets:		**(in thousands)**	
Risk Management Assets	$ 34,564	$ (1,006)	$ 33,558
Prepayments and Other	11,877	(1,917)	9,960
Long-term Risk Management Assets	43,352	(1,500)	41,852
Current Liabilities:			
Risk Management Liabilities	30,118	(1,881)	28,237
Customer Deposits	45,602	(2,507)	43,095
Long-term Risk Management Liabilities	27,454	(35)	27,419

I&M

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the September 2008 10-Q
Current Assets:		**(in thousands)**	
Risk Management Assets	$ 33,334	$ (969)	$ 32,365
Prepayments and Other	12,932	(1,841)	11,091
Long-term Risk Management Assets	41,668	(1,441)	40,227
Current Liabilities:			
Risk Management Liabilities	29,078	(1,807)	27,271
Customer Deposits	28,855	(2,410)	26,445
Long-term Risk Management Liabilities	26,382	(34)	26,348

OPCo

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the September 2008 10-Q
Current Assets:		(in thousands)	
Risk Management Assets	$ 45,490	$ (1,254)	$ 44,236
Prepayments and Other	20,532	(2,232)	18,300
Long-term Risk Management Assets	51,334	(1,748)	49,586
Current Liabilities:			
Risk Management Liabilities	42,740	(2,192)	40,548
Customer Deposits	33,615	(3,002)	30,613
Long-term Risk Management Liabilities	32,234	(40)	32,194

PSO

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the September 2008 10-Q
Current Assets:		(in thousands)	
Risk Management Assets	$ 33,338	$ (30)	$ 33,308
Margin Deposits	9,119	(139)	8,980
Long-term Risk Management Assets	3,376	(18)	3,358
Current Liabilities:			
Risk Management Liabilities	27,151	(33)	27,118
Customer Deposits	41,525	(48)	41,477
Long-term Risk Management Liabilities	2,914	(106)	2,808

SWEPCo

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the September 2008 10-Q
Current Assets:		(in thousands)	
Risk Management Assets	$ 39,893	$ (43)	$ 39,850
Margin Deposits	10,814	(164)	10,650
Long-term Risk Management Assets	4,095	(22)	4,073
Current Liabilities:			
Risk Management Liabilities	32,668	(39)	32,629
Customer Deposits	37,537	(64)	37,473
Long-term Risk Management Liabilities	3,460	(126)	3,334

For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the September 30, 2008 balance sheets, the Registrant Subsidiaries netted collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

	September 30, 2008	
	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in thousands)	
APCo	$ 8,250	$ 597
CSPCo	4,631	311
I&M	4,482	309
OPCo	5,747	656
PSO	499	47
SWEPCo	588	69

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, management cannot determine the impact on the reporting of the Registrant Subsidiaries' operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, leases, hedge accounting, consolidation policy, trading inventory and related tax impacts. Management also expects 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 future net income and financial position.

EXTRAORDINARY ITEM

APCo recorded an extraordinary loss of $118 million ($79 million, net of tax) during the second quarter of 2007 for the establishment of regulatory assets and liabilities related to the Virginia generation operations. In 2000, APCo discontinued SFAS 71 regulatory accounting for the Virginia jurisdiction due to the passage of legislation for customer choice and deregulation. In April 2007, Virginia passed legislation to establish electric regulation again.

3. RATE MATTERS

The Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2007 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2008 and updates the 2007 Annual Report.

Ohio Rate Matters

Ohio Electric Security Plan Filings – Affecting CSPCo and OPCo

In April 2008, the Ohio legislature passed Senate Bill 221, which amends the restructuring law effective July 31, 2008 and requires electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities may file an ESP with a fuel cost recovery mechanism. Electric utilities also have an option to file a Market Rate Offer (MRO) for generation pricing. A MRO, from the date of its commencement, could transition CSPCo and OPCo to full market rates no sooner than six years and no later than ten years after the PUCO approves a MRO. The PUCO has the authority to approve or modify each utilities' ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than a MRO. Both alternatives involve a "substantially excessive earnings" test based on what public companies, including other utilities with similar risk profiles, earn on equity. Management has preliminarily concluded, pending the outcome of the ESP proceeding, that CSPCo's and OPCo's generation/supply operations are not subject to cost-based rate regulation accounting. However, if a fuel cost recovery mechanism is implemented within the ESP, CSPCo's and OPCo's fuel and purchased power operations would be subject to cost-based rate regulation accounting. Management is unable to predict the financial statement impact of the restructuring legislation until the PUCO acts on specific proposals made by CSPCo and OPCo in their ESPs.

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file an optional MRO. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism (which excludes off-system sales) that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The increases in customer bills related to the fuel-purchased power cost recovery mechanism would be phased-in over the three year period from 2009 through 2011. If the ESP is approved as filed, effective with January 2009 billings, CSPCo and OPCo will defer any fuel cost under-recoveries and related carrying costs for future recovery. The under-recoveries and related carrying costs that exist at the end of 2011 will be recovered over seven years from 2012 through 2018. In addition to the fuel cost recovery mechanisms, the requested increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for distribution reliability costs and for unexpected non-fuel generation costs. The filings also include programs for smart metering initiatives and economic development and mandated energy efficiency and peak demand reduction programs. In September 2008, the PUCO issued a finding and order tentatively adopting rules governing MRO and ESP applications. CSPCo and OPCo filed their ESP applications based on proposed rules and requested waivers for portions of the proposed rules. The PUCO denied the waiver requests in September 2008 and ordered CSPCo and OPCo to submit information consistent with the tentative rules. In October 2008, CSPCo and OPCo submitted additional information related to proforma financial statements and information concerning CSPCo and OPCo's fuel procurement process. In October 2008, CSPCo and OPCo filed an application for rehearing with the PUCO to challenge certain aspects of the proposed rules.

Within the ESPs, CSPCo and OPCo would also recover existing regulatory assets of $46 million and $38 million, respectively, for customer choice implementation and line extension carrying costs. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $30 million and $21 million, respectively. Such costs would be recovered over an 8-year period beginning January 2011. Hearings are scheduled for November 2008 and an order is expected in the fourth quarter of 2008. If an order is not received prior to January 1, 2009, CSPCo and OPCo have requested retroactive application of the new rates back to January 1, 2009 upon approval. Failure of the PUCO to ultimately approve the recovery of the regulatory assets would have an adverse effect on future net income and cash flows.

2008 Generation Rider and Transmission Rider Rate Settlement – Affecting CSPCo and OPCo

On January 30, 2008, the PUCO approved a settlement agreement, among CSPCo, OPCo and other parties, under the additional average 4% generation rate increase and transmission cost recovery rider (TCRR) provisions of the RSP. The increase was to recover additional governmentally-mandated costs including incremental environmental costs. Under the settlement, the PUCO also approved recovery through the TCRR of increased PJM costs associated with transmission line losses of $39 million each for CSPCo and OPCo. As a result, CSPCo and OPCo established regulatory assets during the first quarter of 2008 of $12 million and $14 million, respectively, related to the future recovery of increased PJM billings previously expensed from June 2007 to December 2007 for transmission line losses. The PUCO also approved a credit applied to the TCRR of $10 million for OPCo and $8 million for CSPCo for a reduction in PJM net congestion costs. To the extent that collections for the TCRR recoveries are under/over actual net costs, CSPCo and OPCo will defer the difference as a regulatory asset or regulatory liability and adjust future customer billings to reflect actual costs, including carrying costs on the deferral. Under the terms of the settlement, although the increased PJM costs associated with transmission line losses will be recovered through the TCRR, these recoveries will still be applied to reduce the annual average 4% generation rate increase limitation. In addition, the PUCO approved recoveries through generation rates of environmental costs and related carrying costs of $29 million for CSPCo and $5 million for OPCo. These RSP rate adjustments were implemented in February 2008.

Also, in February 2008, Ormet, a major industrial customer, filed a motion to intervene and an application for rehearing of the PUCO's January 2008 RSP order claiming the settlement inappropriately shifted $4 million in cost recovery to Ormet. In March 2008, the PUCO granted Ormet's motion to intervene. Ormet's rehearing application also was granted for the purpose of providing the PUCO with additional time to consider the issues raised by Ormet. Upon PUCO approval of an unrelated amendment to the Ormet contract, Ormet withdrew its rehearing application in August 2008.

Ohio IGCC Plant – Affecting CSPCo and OPCo

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the generation rates which may be a market-based standard service offer price for generation and the expected higher cost of operating and maintaining the plant, including a return on and return of the projected cost to construct the plant.

In June 2006, the PUCO issued an order approving a tariff to allow CSPCo and OPCo to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. During that period CSPCo and OPCo each collected $12 million in pre-construction costs and 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 within five years of the June 2006 PUCO order, all Phase 1 cost recoveries associated with items that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 pending further hearings.

In August 2006, intervenors filed four separate appeals of the PUCO's order in the IGCC proceeding. In March 2008, the Ohio Supreme Court issued its opinion affirming in part, and reversing in part the PUCO's order and remanded the matter back to the PUCO. The Ohio Supreme Court held that while there could be an opportunity under existing law to recover a portion of the IGCC costs in distribution rates, traditional rate making procedures would apply to the recoverable portion. The Ohio Supreme Court did not address the matter of refunding the Phase 1 cost recovery and declined to create an exception to its precedent of denying claims for refund of past recoveries from approved orders of the PUCO. In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all Phase 1 costs be refunded to Ohio ratepayers with interest because the Ohio Supreme Court invalidated the underlying foundation for the Phase 1 recovery. CSPCo and OPCo filed a motion with the PUCO that argued the Ohio Consumers' Counsel's motion was without legal merit and contrary to past precedent. If CSPCo and OPCo were required to refund the $24 million collected and those costs were not recoverable in another jurisdiction in connection with the construction of an IGCC plant, it would have an adverse effect on future net income and cash flows.

As of December 31, 2007, the cost of the plant was estimated at $2.7 billion. The estimated cost of the plant has continued to increase significantly. Management continues to pursue the ultimate construction of the IGCC plant. CSPCo and OPCo will not start construction of the IGCC plant until sufficient assurance of regulatory cost recovery exists.

Ormet – Affecting CSPCo and OPCo

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load, in accordance with a settlement agreement approved by the PUCO. The settlement agreement allows for the recovery in 2007 and 2008 of the difference between the $43 per MWH Ormet pays for power and a PUCO-approved market price, if higher. The PUCO approved a $47.69 per MWH market price for 2007 and the difference was recovered through the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) excess deferred tax regulatory liability resulting from an Ohio franchise tax phase-out recorded in 2005.

CSPCo and OPCo each amortized $8 million of this regulatory liability to income for the nine months ended September 30, 2008 based on the previously approved 2007 price of $47.69 per MWH. In December 2007, CSPCo and OPCo submitted for approval a market price of $53.03 per MWH for 2008. The PUCO has not yet approved the 2008 market price. If the PUCO approves a market price for 2008 below $47.69, it could have an adverse effect on future net income and cash flows. A price above $47.69 should result in a favorable effect. If CSPCo and OPCo serve the Ormet load after 2008 without any special provisions, they could experience incremental costs to acquire additional capacity to meet their reserve requirements and/or forgo more profitable market-priced off-system sales.

Hurricane Ike – Affecting CSPCo and OPCo

In September 2008, the service territories of CSPCo and OPCo were impacted by strong winds from the remnants of Hurricane Ike. CSPCo and OPCo incurred approximately $18 million and $13 million, respectively, in incremental distribution operation and maintenance costs related to service restoration efforts. Under the current RSP, CSPCo and OPCo can seek a distribution rate adjustment to recover incremental distribution expenses related to major storm service restoration efforts. In September 2008, CSPCo and OPCo established regulatory assets of $17 million and $10 million, respectively, for the incremental distribution operation and maintenance costs related to major storm service restoration efforts. The regulatory assets represent the excess above the average of the last three years of distribution storm expenses excluding Hurricane Ike, which was the methodology used by the PUCO to determine the recoverable amount of storm restoration expenses in the most recent 2006 PUCO storm damage recovery decision. Prior to December 31, 2008, which is the expiration of the RSP, CSPCo and OPCo will file for recovery of the regulatory assets. As a result of the past favorable treatment of storm restoration costs and the favorable RSP provisions, management believes the recovery of the regulatory assets is probable. If these regulatory assets are not recoverable, it would have an adverse effect on future net income and cash flows.

Virginia Rate Matters

Virginia Base Rate Filing – Affecting APCo

In May 2008, APCo filed an application with the Virginia SCC to increase its base rates by $208 million on an annual basis. The requested increase is based upon a calendar 2007 test year adjusted for changes in revenues, expenses, rate base and capital structure through June 2008. This is consistent with the ratemaking treatment adopted by the Virginia SCC in APCo's 2006 base rate case. The proposed revenue requirement reflects a return on equity of 11.75%. Hearings began in October 2008. As permitted under Virginia law, APCo implemented these new base rates, subject to refund, effective October 28, 2008.

In September 2008, the Attorney General's office filed testimony recommending the proposed $208 million annual increase in base rate be reduced to $133 million. The decrease is principally due to the use of a return on equity approved in the last base rate case of 10% and various rate base and operating income adjustments, including a $25 million proposed disallowance of capacity equalization charges payable by APCo as a deficit member of the FERC approved AEP Power Pool.

In October 2008, the Virginia SCC staff filed testimony recommending the proposed $208 million annual increase in base rate be reduced to $157 million. The decrease is principally due to the use of a recommended return on equity of 10.1%. In October 2008, hearings were held in which APCo filed a $168 million settlement agreement which was accepted by all parties except one industrial customer. APCo expects to receive a final order from the Virginia SCC in November 2008.

Virginia E&R Costs Recovery Filing – Affecting APCo

As of September 2008, APCo has $118 million of deferred Virginia incremental E&R costs (excluding $25 million of unrecognized equity carrying costs). The $118 million consists of $6 million already approved by the Virginia SCC to be collected during the fourth quarter 2008, $54 million relating to APCo's May 2008 filing for recovery in 2009, and $58 million, representing costs deferred in 2008 to date, to be included (along with the fourth quarter 2008 E&R deferrals) in the 2009 E&R filing, to be collected in 2010.

In September 2008, a settlement was reached between the parties to the 2008 filing and a stipulation agreement (stipulation) was submitted to the hearing examiner. The stipulation provides for recovery of $61 million of incremental E&R costs in 2009 which is an increase of $12 million over the level of E&R surcharge revenues being collected in 2008. The stipulation included an unfavorable $1 million adjustment related to certain costs considered not recoverable E&R costs and recovery of $4.5 million representing one-half of a $9 million Virginia jurisdictional portion of NSR settlement expenses recorded in 2007. In accordance with the stipulation, APCo will request the remaining one-half of the $9 million of NSR settlement expenses in APCo's 2009 E&R filing. The stipulation also specifies that APCo will remove $3 million of the $9 million of NSR settlement expenses requested to be recovered over 3 years in the current base rate case from the base rate case's revenue requirement.

In September 2008, the hearing examiner recommended that the Virginia SCC accept the stipulation. As a result, in September 2008, APCo deferred as a regulatory asset $9 million of NSR settlement expenses it had expensed in 2007 that have become probable of future recovery. In October 2008, the Virginia SCC approved the stipulation which will have a favorable effect on 2009 future cash flows of $61 million and on net income for the previously unrecognized equity costs of approximately $11 million. If the Virginia SCC were to disallow a material portion of APCo's 2008 deferral, it would have an adverse effect on future net income and cash flows.

Virginia Fuel Clause Filings – Affecting APCo

In July 2007, APCo filed an application with the Virginia SCC to seek an annualized increase, effective September 1, 2007, of $33 million for fuel costs and sharing of off-system sales.

In February 2008, the Virginia SCC issued an order that approved a reduced fuel factor effective with the February 2008 billing cycle. The order terminated the off-system sales margin rider and approved a 75%-25% sharing of off-system sales margins between customers and APCo effective September 1, 2007 as required by the re-regulation legislation in Virginia. The order also allows APCo to include in its monthly under/over recovery deferrals the

Virginia jurisdictional share of PJM transmission line loss costs from June 2007. The adjusted factor increases annual fuel clause revenues by $4 million. The order authorized the Virginia SCC staff and other parties to make specific recommendations to the Virginia SCC in APCo's next fuel factor proceeding to ensure accurate assignment of the prudently incurred PJM transmission line loss costs to APCo's Virginia jurisdictional operations. Management believes the incurred PJM transmission line loss costs are prudently incurred and are being properly assigned to APCo's Virginia jurisdictional operations.

In July 2008, APCo filed its next fuel factor proceeding with the Virginia SCC and requested an annualized increase of $132 million effective September 1, 2008. The increase primarily relates to increases in coal costs. In August 2008, the Virginia SCC issued an order to allow APCo to implement the increased fuel factor on an interim basis for services rendered after August 2008. In September 2008, the Virginia SCC staff filed testimony recommending a lower fuel factor which will result in an annualized increase of $117 million, which includes the PJM transmission line loss costs, instead of APCo's proposed $132 million. In October 2008, the Virginia SCC ordered an annualized increase of $117 million for services rendered on and after October 20, 2008.

APCo's Virginia SCC Filing for an IGCC Plant – Affecting APCo

In July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover initial costs associated with a proposed 629 MW IGCC plant to be constructed in Mason County, West Virginia adjacent to APCo's existing Mountaineer Generating Station for an estimated cost of $2.2 billion. The filing requested recovery of an estimated $45 million over twelve months beginning January 1, 2009 including a return on projected CWIP and development, design and planning pre-construction costs incurred from July 1, 2007 through December 31, 2009. APCo also requested authorization to defer a return on deferred pre-construction costs incurred beginning July 1, 2007 until such costs are recovered. Through September 30, 2008, APCo has deferred for future recovery pre-construction IGCC costs of approximately $9 million allocated to Virginia jurisdictional operations.

The Virginia SCC issued an order in April 2008 denying APCo's requests stating the belief that the estimated cost may be significantly understated. The Virginia SCC also expressed concern that the $2.2 billion estimated cost did not include a retrofitting of carbon capture and sequestration facilities. In April 2008, APCo filed a petition for reconsideration in Virginia. In May 2008, the Virginia SCC denied APCo's request to reconsider its previous ruling. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expense being incurred and certification of the IGCC plant prior to July 2010. Although management continues to pursue the construction of the IGCC plant, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

Mountaineer Carbon Capture Project – Affecting APCo

In January 2008, APCo and ALSTOM Power Inc. (Alstom), an unrelated third party, entered into an agreement to jointly construct a CO_2 capture facility. APCo and Alstom will each own part of the CO_2 capture facility. APCo will also construct and own the necessary facilities to store the CO_2. APCo's estimated cost for its share of the facilities is $76 million. Through September 30, 2008, APCo incurred $13 million in capitalized project costs which is included in Regulatory Assets. APCo plans to seek recovery for the CO_2 capture and storage project costs in its next Virginia and West Virginia base rate filings which are expected to be filed in 2009. APCo is presently seeking a return on the capitalized project costs in its current Virginia base rate filing. The Attorney General has recommended that the project costs should be shared by all affiliated operating companies with coal-fired generation plants. If a significant portion of the project costs are excluded from base rates and ultimately disallowed in Virginia and/or West Virginia, it could have an adverse effect on future net income and cash flows.

West Virginia Rate Matters

APCo's 2008 Expanded Net Energy Cost (ENEC) Filing – Affecting APCo

In February 2008, APCo filed for an increase of approximately $140 million including a $122 million increase in the ENEC, a $15 million increase in construction cost surcharges and $3 million of reliability expenditures, to become effective July 2008. In June 2008, the WVPSC issued an order approving a joint stipulation and settlement agreement granting rate increases, effective July 2008, of approximately $95 million, including a $79 million increase in the ENEC, a $13 million increase in construction cost surcharges and $3 million of reliability expenditures. The ENEC is an expanded form of fuel clause mechanism, which includes all energy-related costs including fuel, purchased power expenses, off-system sales credits, PJM costs associated with transmission line losses due to the implementation of marginal loss pricing and other energy/transmission items.

The ENEC is subject to a true-up to actual costs and should have no earnings effect if actual costs exceed the recoveries due to the deferral of any over/under-recovery of ENEC costs. The construction cost and reliability surcharges are not subject to a true-up to actual costs and could impact future net income and cash flows.

APCo's West Virginia IGCC Plant Filing – Affecting APCo

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity (CCN) to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer Generating Station in Mason County, West Virginia.

In June 2007, APCo filed testimony with the WVPSC supporting the requests for a CCN and for pre-approval of a surcharge rate mechanism to provide for the timely recovery of both 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. In March 2008, the WVPSC granted APCo the CCN to build the plant and the request for cost recovery. Also, in March 2008, various intervenors filed petitions with the WVPSC to reconsider the order. No action has been taken on the requests for rehearing. At the time of the filing, the cost of the plant was estimated at $2.2 billion. As of September 30, 2008, the estimated cost of the plant has continued to significantly increase. In July 2008, based on the unfavorable order received in Virginia, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed. See the "APCo's Virginia SCC Filing for an IGCC Plant" section above. Through September 30, 2008, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to the West Virginia jurisdiction and approximately $2 million applicable to the FERC jurisdiction. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant. Although management continues to pursue the ultimate construction of the IGCC plant, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

Indiana Rate Matters

Indiana Base Rate Filing – Affecting I&M

In a January 2008, filing with the IURC, updated in the second quarter of 2008, I&M requested an increase in its Indiana base rates of $80 million including a return on equity of 11.5%. The base rate increase includes the $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. The depreciation reduction will no longer favorably impact earnings and will adversely affect cash flows when tariff rates are revised to reflect the effect of the depreciation expense reduction. The filing also requests trackers for certain variable components of the cost of service including recently increased PJM costs associated with transmission line losses due to the implementation of marginal loss pricing and other RTO costs, reliability enhancement costs, demand side management/energy efficiency costs, off-system sales margins and environmental compliance costs. The trackers would initially increase annual revenues by an additional $45 million. I&M proposes to share with ratepayers, through a tracker, 50% of off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million.

In September 2008, the Indiana Office of Utility Consumer Counselor (OUCC) and the Industrial Customer Coalition filed testimony recommending a $14 million and $37 million decrease in revenue, respectively. Two other intervenors filed testimony on limited issues. The OUCC and the Industrial Customer Coalition recommended that the IURC reduce the ROE proposed by I&M, reduce or limit the amount of off-system sales margin sharing, deny the recovery of reliability enhancement costs and reject the proposed environmental compliance cost recovery trackers. In October 2008, I&M filed testimony rebutting the recommendations of the OUCC. Hearings are scheduled for December 2008. A decision is expected from the IURC by June 2009.

Michigan Rate Matters

Michigan Restructuring – Affecting I&M

Although customer choice commenced for I&M's Michigan customers on January 1, 2002, I&M's rates for generation in Michigan continued to be cost-based regulated because none of I&M's customers elected to change suppliers and no alternative electric suppliers were registered to compete in I&M's Michigan service territory. In October 2008, the Governor of Michigan signed legislation to limit customer choice load to no more than 10% of the annual retail load for the preceding calendar year and to require the remaining 90% of annual retail load to be phased into cost-based rates. The new legislation also requires utilities to meet certain energy efficiency and renewable portfolio standards and requires cost recovery of meeting those standards. Management continues to conclude that I&M's rates for generation in Michigan are cost-based regulated.

Oklahoma Rate Matters

PSO Fuel and Purchased Power – Affecting PSO

The Oklahoma Industrial Energy Consumers appealed an ALJ recommendation in June 2008 regarding a pending fuel case involving the reallocation of $42 million of purchased power costs among AEP West companies in 2002. The Oklahoma Industrial Energy Consumers requested that PSO be required to refund this $42 million of reallocated purchased power costs through its fuel clause. PSO had recovered the $42 million during the period June 2007 through May 2008. In August 2008, the OCC heard the appeal and a decision is pending.

In February 2006, the OCC enacted a rule, requiring the OCC staff to conduct prudence reviews on PSO's generation and fuel procurement processes, practices and costs on a periodic basis. PSO filed testimony in June 2007 covering a prudence review for the year 2005. The OCC staff and intervenors filed testimony in September 2007, and hearings were held in November 2007. The only major issue in the proceeding was the alleged under allocation of off-system sales credits under the FERC-approved allocation methodology, which previously was determined not to be jurisdictional to the OCC. See "Allocation of Off-system Sales Margins" section within "FERC Rate Matters". Consistent with the prior OCC determination, the ALJ found that the OCC lacked authority to alter the FERC-approved allocation methodology and that PSO's fuel costs were prudent. The intervenors appealed the ALJ recommendation and the OCC heard the appeal in August 2008. In August 2008, the OCC filed a complaint at the FERC alleging that AEPSC inappropriately allocated off-system trading margins between the AEP East companies and the AEP West companies and did not properly allocate off-system trading margins within the AEP West companies.

In November 2007, PSO filed testimony in another proceeding to address its fuel costs for 2006. In April 2008, intervenor testimony was filed again challenging the allocation of off-system sales credits during the portion of the year when the allocation was in effect. Hearings were held in July 2008 and the OCC changed the scope of the proceeding from a prudence review to only a review of the mechanics of the fuel cost calculation. No party contested PSO's fuel cost calculation. In August 2008, the OCC issued a final order that PSO's calculations of fuel and purchased power costs were accurate and are consistent with PSO's fuel tariff.

In September 2008, the OCC initiated a review of PSO's generation, purchased power and fuel procurement processes and costs for 2007. Under the OCC minimum filing requirements, PSO is required to file testimony and supporting data within 60 days which will occur in the fourth quarter of 2008. Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings or prudence reviews. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and therefore are legally recoverable.

Red Rock Generating Facility – Affecting PSO

In July 2006, PSO announced an agreement with Oklahoma Gas and Electric Company (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit. PSO would own 50% of the new unit. Under the agreement, OG&E would manage construction of the plant. OG&E and PSO requested pre-approval to construct the coal-fired Red Rock Generating Facility (Red Rock) and to implement a recovery rider.

In October 2007, the OCC issued a final order approving PSO's need for 450 MWs of additional capacity by the year 2012, but rejected the ALJ's recommendation and denied PSO's and OG&E's applications for construction pre-approval. The OCC stated that PSO failed to fully study other alternatives to a coal-fired plant. Since PSO and OG&E could not obtain pre-approval to build Red Rock, PSO and OG&E cancelled the third party construction contract and their joint venture development contract. In June 2008, PSO issued a request-for-proposal to meet its capacity and energy needs.

In December 2007, PSO filed an application at the OCC requesting recovery of $21 million in pre-construction costs and contract cancellation fees associated with Red Rock. In March 2008, PSO and all other parties in this docket signed a settlement agreement that provides for recovery of $11 million of Red Rock costs, and provides carrying costs at PSO's AFUDC rate beginning in March 2008 and continuing until the $11 million is included in PSO's next base rate case. PSO will recover the costs over the expected life of the peaking facilities at the Southwestern Station, and include the costs in rate base in its next base rate filing. The settlement was filed with the OCC in March 2008. The OCC approved the settlement in May 2008. As a result of the settlement, PSO wrote off $10 million of its deferred pre-construction costs/cancellation fees in the first quarter of 2008. In July 2008, PSO filed a base rate case which included $11 million of deferred Red Rock costs plus carrying charges at PSO's AFUDC rate beginning in March 2008. See "2008 Oklahoma Base Rate Filing" section below.

Oklahoma 2007 Ice Storms – Affecting PSO

In October 2007, PSO filed with the OCC requesting recovery of $13 million of operation and maintenance expense related to service restoration efforts after a January 2007 ice storm. PSO proposed in its application to establish a regulatory asset of $13 million to defer the previously expensed January 2007 ice storm restoration costs and to amortize the regulatory asset coincident with gains from the sale of excess SO_2 emission allowances. In December 2007, PSO expensed approximately $70 million of additional storm restoration costs related to the December 2007 ice storm.

In February 2008, PSO entered into a settlement agreement for recovery of costs from both ice storms. In March 2008, the OCC approved the settlement subject to an audit of the final December ice storm costs filed in July 2008. As a result, PSO recorded an $81 million regulatory asset for ice storm maintenance expenses and related carrying costs less $9 million of amortization expense to offset recognition of deferred gains from sales of SO_2 emission allowances. Under the settlement agreement, PSO would apply proceeds from sales of excess SO_2 emission allowances of an estimated $26 million to recover part of the ice storm regulatory asset. The settlement also provided for PSO to amortize and recover the remaining amount of the regulatory asset through a rider over a period of five years beginning in the fourth quarter of 2008. The regulatory asset will earn a return of 10.92% on the unrecovered balance.

In June 2008, PSO adjusted its regulatory asset to true-up the estimated costs to actual costs. After the true-up, application of proceeds from to-date sales of excess SO_2 emission allowances and carrying costs, the ice storm regulatory asset was $64 million. The estimate of future gains from the sale of SO_2 emission allowances has significantly declined with the decrease in value of such allowances. As a result, estimated collections from customers through the special storm damage recovery rider will be higher than the estimate in the settlement agreement. In July 2008, as required by the settlement agreement, PSO filed its reconciliation of the December 2007 storm restoration costs along with a proposed tariff to recover the amounts not offset by the sales of SO_2 emission allowances. In September 2008, the OCC staff filed testimony supporting PSO's filing with minor changes. In October 2008, an ALJ recommended that PSO recover $62 million of the December 2007 storm restoration costs before consideration of emission allowance gains and carrying costs. In October 2008, the OCC approved the filing which allows PSO to recover $62 million of the December 2007 storm restoration costs beginning in November 2008.

2008 Oklahoma Annual Fuel Factor Filing – Affecting PSO

In May 2008, pursuant to its tariff, PSO filed its annual update with the OCC for increases in the various service level fuel factors based on estimated increases in fuel costs, primarily natural gas and purchased power expenses, of approximately $300 million. The request included recovery of $26 million in under-recovered deferred fuel. In June 2008, PSO implemented the fuel factor increase. Because of the substantial increase, the OCC held an administrative proceeding to determine whether the proposed charges were based upon the appropriate coal, purchased gas and purchased power prices and were properly computed. In June 2008, the OCC ordered that PSO properly estimated the increase in natural gas prices, properly determined its fuel costs and, thus, should implement the increase.

2008 Oklahoma Base Rate Filing – Affecting PSO

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million on an annual basis. PSO recovers costs related to new peaking units recently placed into service through the Generation Cost Recovery Rider (GCRR). Upon implementation of the new base rates, PSO will recover these costs through the new base rates and the GCRR will terminate. Therefore, PSO's net annual requested increase in total revenues is actually $117 million. The requested increase is based upon a test year ended February 29, 2008, adjusted for known and measurable changes through August 2008, which is consistent with the ratemaking treatment adopted by the OCC in PSO's 2006 base rate case. The proposed revenue requirement reflects a return on equity of 11.25%. PSO expects hearings to begin in December 2008 and new base rates to become effective in the first quarter of 2009. In October 2008, the OCC staff, the Attorney General's office, and a group of industrial customers filed testimony recommending annual base rate increases of $86 million, $68 million and $29 million, respectively. The differences are principally due to the use of recommended return on equity of 10.88%, 10% and 9.5% by the OCC staff, the Attorney General's office, and a group of industrial customers. The OCC staff and the Attorney General's office recommended $22 million and $8 million, respectively, of costs included in the filing be recovered through the fuel adjustment clause and riders outside of base rates.

Louisiana Rate Matters

Louisiana Compliance Filing – Affecting SWEPCo

In connection with SWEPCo's merger related compliance filings, the LPSC approved a settlement agreement in April 2008 that prospectively resolves all issues regarding claims that SWEPCo had over-earned its allowed return. SWEPCo agreed to a formula rate plan (FRP) with a three-year term. Under the plan, beginning in August 2008, rates shall be established to allow SWEPCo to earn an adjusted return on common equity of 10.565%. The adjustments are standard Louisiana rate filing adjustments.

If in the second and third year of the FRP, the adjusted earned return is within the range of 10.015% to 11.115%, no adjustment to rates is necessary. However, if the adjusted earned return is outside of the above-specified range, an FRP rider will be established to increase or decrease rates prospectively. If the adjusted earned return is less than 10.015%, SWEPCo will prospectively increase rates to collect 60% of the difference between 10.565% and the adjusted earned return. Alternatively, if the adjusted earned return is more than 11.115%, SWEPCo will prospectively decrease rates by 60% of the difference between the adjusted earned return and 10.565%. SWEPCo will not record over/under recovery deferrals for refund or future recovery under this FRP.

The settlement provides for a separate credit rider decreasing Louisiana retail base rates by $5 million prospectively over the entire three-year term of the FRP, which shall not affect the adjusted earned return in the FRP calculation. This separate credit rider will cease effective August 2011.

In addition, the settlement provides for a reduction in generation depreciation rates effective October 2007. SWEPCo deferred as a regulatory liability, the effects of the expected depreciation reduction through July 2008. SWEPCo will amortize this regulatory liability over the three-year term of the FRP as a reduction to the cost of service used to determine the adjusted earned return. In August 2008, the LPSC issued an order approving the settlement.

In April 2008, SWEPCo filed the first FRP which would increase its annual Louisiana retail rates by $11 million in August 2008 to earn an adjusted return on common equity of 10.565%. In accordance with the settlement, SWEPCo recorded a $4 million regulatory liability related to the reduction in generation depreciation rates. The amount of the unamortized regulatory liability for the reduction in generation depreciation was $4 million as of September 30, 2008. In August 2008, SWEPCo implemented the FRP rates, subject to refund, as the LPSC staff reviews SWEPCo's FRP filing and the production depreciation study.

Stall Unit – Affecting SWEPCo

In May 2006, SWEPCo announced plans to build a new intermediate load, 500 MW, natural gas-fired, combustion turbine, combined cycle generating unit (the Stall Unit) at its existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo submitted the appropriate filings to the PUCT, the APSC, the LPSC and the Louisiana Department of Environmental Quality to seek approvals to construct the unit. The Stall Unit is currently estimated to cost $378 million, excluding AFUDC, and is expected to be in-service in mid-2010.

In March 2007, the PUCT approved SWEPCo's request for a certificate for the facility based on a prior cost estimate. In September 2008, the LPSC approved SWEPCo's request for certification to construct the Stall Unit. The APSC has not established a procedural schedule at this time. The Louisiana Department of Environmental Quality issued an air permit for the unit in March 2008. If SWEPCo does not receive appropriate authorizations and permits to build the Stall Unit, SWEPCo would seek recovery of the capitalized pre-construction costs including any cancellation fees. As of September 30, 2008, SWEPCo has capitalized pre-construction costs of $158 million and has contractual construction commitments of an additional $145 million. As of September 30, 2008, if the plant had been cancelled, cancellation fees of $61 million would have been required in order to terminate these construction commitments. If SWEPCo cancels the plant and cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

Turk Plant – Affecting SWEPCo

See "Turk Plant" section within Arkansas Rate Matters for disclosure.

Arkansas Rate Matters

Turk Plant – Affecting SWEPCo

In August 2006, SWEPCo announced plans to build the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. Ultra-supercritical technology uses higher temperatures and higher pressures to produce electricity more efficiently thereby using less fuel and providing substantial emissions reductions. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking certification of the plant. SWEPCo will own 73% of the Turk Plant and will operate the facility. During 2007, SWEPCo signed joint ownership agreements with the Oklahoma Municipal Power Authority (OMPA), the Arkansas Electric Cooperative Corporation (AECC) and the East Texas Electric Cooperative (ETEC) for the remaining 27% of the Turk Plant. The Turk Plant is currently estimated to cost $1.5 billion, excluding AFUDC, with SWEPCo's portion estimated to cost $1.1 billion. If approved on a timely basis, the plant is expected to be in-service in 2012.

In November 2007, the APSC granted approval to build the plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant.

In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the $1.5 billion projected construction cost, excluding AFUDC, (b) capping CO_2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. An intervenor filed a motion for rehearing seeking reversal of the PUCT's decision. SWEPCo filed a motion for rehearing stating that the two cost cap restrictions are unlawful. In September 2008, the motions for rehearing were denied. In October 2008, SWEPCo appealed the PUCT's order regarding the two cost cap restrictions. If the cost cap restrictions are upheld and construction or emissions costs exceed the restrictions, it could have a material adverse impact on future net income and cash flows. In October 2008, an intervenor filed an appeal contending that the PUCT's grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

SWEPCo is also working with the Arkansas Department of Environmental Quality for the approval of an air permit and the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. Once SWEPCo receives the air permit, they will commence construction. A request to stop pre-construction activities at the site was filed in Federal court by the same Arkansas landowners who appealed the APSC decision to the Arkansas State Court of Appeals. In July 2008, the Federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In January 2008 and July 2008, SWEPCo filed applications for authority with the APSC to construct transmission lines necessary for service from the Turk Plant. Several landowners filed for intervention status and one landowner also contended he should be permitted to re-litigate Turk Plant issues, including the need for the generation. The APSC granted their intervention but denied the request to re-litigate the Turk Plant issues. The landowner filed an appeal to the Arkansas State Court of Appeals in June 2008.

The Arkansas Governor’s Commission on Global Warming is scheduled to issue its final report to the Governor by November 1, 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. If legislation is passed as a result of the findings in the Commission’s report, it could impact SWEPCo’s proposal to build the Turk Plant.

If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of September 30, 2008, SWEPCo has capitalized approximately $448 million of expenditures and has significant contractual construction commitments for an additional $771 million. As of September 30, 2008, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $61 million. If the Turk Plant does not receive all necessary approvals on reasonable terms and SWEPCo cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

Stall Unit – Affecting SWEPCo

See “Stall Unit” section within Louisiana Rate Matters for disclosure.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC – Affecting APCo, CSPCo, I&M and OPCo

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at 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 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues. APCo’s, CSPCo’s, I&M’s and OPCo’s portions of recognized gross SECA revenues are as follows:

Company	(in millions)
APCo	$ 70.2
CSPCo	38.8
I&M	41.3
OPCo	53.3

In August 2006, a FERC 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 the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, 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 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 disallowance of a large portion on any unsettled SECA revenues.

During 2006, based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $37 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. APCo's, CSPCo's, I&M's and OPCo's portions of the provision are as follows:

Company	2007	2006
	(in millions)	
APCo	$ 1.7	$ 12.0
CSPCo	0.9	6.7
I&M	1.0	7.0
OPCo	1.3	9.1

AEP has completed settlements totaling $7 million applicable to $75 million of SECA revenues. The balance in the reserve for future settlements as of September 2008 was $35 million. In-process settlements total $3 million applicable to $37 million of SECA revenues. Management believes that the available $32 million of reserves for possible refunds are sufficient to settle the remaining $108 million of contested SECA revenues.

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 will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the remaining reserve of $32 million is adequate to cover all remaining settlements. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if necessary.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them. AEP requested rehearing of this order, which the FERC denied. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 80% of the lost T&O transmission revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future net income and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 20% of the lost T&O transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. Should this effort be successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing – Affecting APCo, CSPCo, I&M and OPCo

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in additional annual revenues of approximately $9 million from nonaffiliated customers within PJM. The remaining $54 million requested would be billed to the AEP East companies to be recovered in retail rates. Retail rates for jurisdictions other than Ohio are not affected until the next base rate filing at FERC. Retail rates for CSPCo and OPCo would be adjusted through the Transmission Cost Recovery Rider (TCRR) totaling approximately $10 million and $12 million, respectively. The TCRR includes a true-up mechanism so CSPCo's and OPCo's net income will not be adversely affected by a FERC ordered transmission rate increase. Other jurisdictions would be recoverable on a lag basis as base rates are changed. AEP requested an effective date of October 1, 2008. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, suspended the effective date until March 1, 2009 and established a settlement proceeding with an ALJ. Management is unable to predict the outcome of this filing.

SPP Transmission Formula Rate Filing – Affecting PSO and SWEPCo

In June 2007, AEPSC filed revised tariffs to establish an up-to-date revenue requirement for SPP transmission services over the facilities owned by PSO and SWEPCo and to implement a transmission cost of service formula rate. PSO and SWEPCo requested an effective date of September 1, 2007 for the revised tariff. If approved as filed, the revised tariff will increase annual network transmission service revenues from nonaffiliated municipal and rural cooperative utilities in the AEP pricing zone of SPP by approximately $10 million. In August 2007, the FERC issued an order conditionally accepting PSO's and SWEPCo's proposed formula rate, subject to a compliance filing, suspended the effective date until February 1, 2008 and established a hearing schedule and settlement proceedings. New rates, subject to refund, were implemented in February 2008. Multiple intervenors have protested or requested re-hearing of the order and settlement discussions are underway. Management believes it has recognized the appropriate amount of revenues, subject to refund, beginning in February 2008. If the final refund exceeds the provisions it would adversely affect future net income and cash flows. Management is unable to predict the outcome of this proceeding.

FERC Market Power Mitigation – Affecting APCo, CSPCo, I&M and OPCo

The FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. Sellers with market rate authority must, at least every three years, update their studies demonstrating lack of market power. In December 2007, AEP filed its most recent triennial update. In March and May 2008, the PUCO filed comments suggesting that the FERC should further investigate whether AEP continues to pass the FERC's indicative screens for the lack of market power in PJM. Certain industrial retail customers also requested the FERC to further investigate this matter. AEP responded that its market power studies were performed in accordance with the FERC's guidelines and continue to demonstrate lack of market power. In September 2008, the FERC issued an order accepting AEP's market-based rates with minor changes and rejected the PUCO's and the industrial retail customers' suggestions to further investigate AEP's lack of market power.

In an unrelated matter, in May 2008, the FERC issued an order in response to a complaint from the state of Maryland's Public Service Commission to hold a future hearing to review the structure of the three pivotal market power supplier tests in PJM. In September 2008, PJM filed a report on the results of the PJM stakeholder process concerning the three pivotal supplier market power tests which recommended the FERC not make major revisions to the test because the test is not unjust or unreasonable.

The FERC's order will become final if no requests for rehearing are filed. If a request for rehearing is filed and ultimately results in a further investigation by the FERC which limits AEP's ability to sell power at market-based rates in PJM, it would result in an adverse effect on future off-system sales margins and cash flows.

Allocation of Off-system Sales Margins – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

In 2004, intervenors and the OCC staff argued that AEP had inappropriately under-allocated off-system sales credits to PSO by $37 million for the period June 2000 to December 2004 under a FERC-approved allocation agreement. An ALJ assigned to hear intervenor claims found that the OCC lacked authority to examine whether AEP deviated from the FERC-approved allocation methodology for off-system sales margins and held that any such complaints should be addressed at the FERC. In October 2007, the OCC adopted the ALJ's recommendation and orally directed the OCC staff to explore filing a complaint at the FERC alleging the allocation of off-system sales margins to PSO is not in compliance with the FERC-approved methodology which could result in an adverse effect on future net income and cash flows for AEP Consolidated, the AEP East companies and the AEP West companies. In June 2008, the ALJ issued a final recommendation and incorporated the prior finding that the OCC lacked authority to review AEP's application of a FERC-approved methodology. In June 2008, the Oklahoma Industrial Energy Consumers appealed the ALJ recommendation to the OCC. In August 2008, the OCC heard the appeal and a decision is pending. See "PSO Fuel and Purchased Power" section within "Oklahoma Rate Matters". In August 2008, the OCC filed a complaint at the FERC alleging that AEPSC inappropriately allocated off-system trading margins between the AEP East companies and the AEP West companies and did not properly allocate off-system trading margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers have all intervened in this filing.

TCC, TNC and the PUCT have been involved in litigation in the federal courts concerning whether the PUCT has the right to order a reallocation of off-system sales margins thereby reducing recoverable fuel costs in the final fuel reconciliation in Texas under the restructuring legislation. In 2005, TCC and TNC recorded provisions for refunds after the PUCT ordered such reallocation. After receipt of favorable federal court decisions and the refusal of the U.S. Supreme Court to hear a PUCT appeal of the TNC decision, TCC and TNC reversed their provisions of $16 million and $9 million, respectively, in the third quarter of 2007.

Management cannot predict the outcome of these proceedings. However, management believes its allocations were in accordance with the then-existing FERC-approved allocation agreements and additional off-system sales margins should not be retroactively reallocated. The results of these proceedings could have an adverse effect on future net income and cash flows for AEP Consolidated, the AEP East companies and the AEP West companies.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation 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 the financial statements. The Commitments, Guarantees and Contingencies note within the 2007 Annual Report should be read in conjunction with this report.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

Certain Registrant Subsidiaries enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits and debt service reserves. These LOCs were issued in the Registrant Subsidiaries' ordinary course of business under the two $1.5 billion credit facilities which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $46 million following its bankruptcy.

In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. As of September 30, 2008, $372 million of letters of credit were issued by Registrant Subsidiaries under the 3-year credit agreement to support variable rate demand notes.

At September 30, 2008, the maximum future payments of the LOCs were as follows:

Company	Amount	Maturity	Borrower Sublimit
	(in thousands)		
$1.5 billion LOC:			
I&M	$ 1,113	March 2009	N/A
SWEPCo	4,000	December 2008	N/A
$650 million LOC:			
APCo	$ 126,717	June 2009	$ 300,000
I&M	77,886	May 2009	230,000
OPCo	166,899	June 2009	400,000

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), an entity consolidated under FIN 46R. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of September 30, 2008, SWEPCo collected approximately $37 million through a rider for final mine closure costs, of which approximately $7 million is recorded in Other Current Liabilities and $30 million is recorded in Deferred Credits and Other on SWEPCo's Condensed 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

All of the Registrant Subsidiaries enter into certain 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, exposure generally does not exceed the sale price. Prior to September 30, 2008, Registrant Subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary. There are no material liabilities recorded for any indemnifications.

The AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Operating Lease

Certain Registrant Subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the Registrant Subsidiaries have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. At September 30, 2008, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Company	Maximum Potential Loss (in millions)
APCo	$ 10
CSPCo	5
I&M	7
OPCo	10
PSO	6
SWEPCo	6

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. AEP intends to maintain the lease for twenty years, via renewal options. 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 over the current lease term from approximately 84% to 77% of the projected fair market value of the equipment.

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 future minimum lease obligation is $20 million for I&M and $23 million for SWEPCo as of September 30, 2008. I&M and SWEPCo intend to renew these leases for the full remaining terms and have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee discussed above is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $14 million ($9 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. However, management believes that the fair market value would produce a sufficient sales price to avoid any loss.

The Registrant Subsidiaries have other railcar lease arrangements that do not utilize this type of financing structure.

CONTINGENCIES

Federal EPA Complaint and Notice of Violation – Affecting CSPCo

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. The alleged modifications occurred over a 20-year period. 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.

The AEP System settled their cases 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 SCR and flue gas desulfurization equipment (FGD or scrubbers) 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 in May 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit.

Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in federal district court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. In April 2008, the parties filed a proposed consent decree to resolve all claims in this case and in the pending appeal of the altered permit for the Welsh Plant. The consent decree requires 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. The consent decree was entered as a final order in June 2008.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant. In April 2005, TCEQ issued an Executive Director's Report (Report) recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo. In 2008, the matter was remanded to TCEQ to pursue settlement discussions. The original Report contained a recommendation to limit the heat input on each Welsh unit to the referenced heat input contained within the state permit within 10 days of the issuance of a final TCEQ order and until the permit is changed. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit and to clarify the sulfur content requirement for fuels consumed at the plant. A permit alteration was issued in March 2007. In June 2007, TCEQ denied a motion to overturn the permit alteration. The permit alteration was appealed to the Travis County District Court, but was resolved by entry of the consent decree in the federal citizen suit action, and dismissed with prejudice in July 2008. Notice of an administrative settlement of the TCEQ enforcement action was published in June 2008. The settlement requires SWEPCo to pay an administrative penalty of $49 thousand and to fund a supplemental environmental project in the amount of $49 thousand, and resolves all violations alleged by TCEQ. In October 2008, TCEQ approved the settlement.

In February 2008, 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. SWEPCo met with the Federal EPA to discuss the alleged violations in March 2008. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit.

Management is unable to predict the timing of any future action by the Federal EPA or the effect of such action on net income, cash flows or financial condition.

Carbon Dioxide (CO_2) Public Nuisance Claims – Affecting AEP East companies and AEP West companies

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 dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the U.S. Supreme Court's decision on this case. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims – Affecting AEP East companies and AEP West companies

In February 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 & 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. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is without merit and intends to defend against the claims.

Clean Air Act Interstate Rule – Affecting Registrant Subsidiaries

In 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR), that required further reductions in SO_2 and NO_x emissions and assists states developing new state implementation plans to meet 1997 national ambient air quality standards (NAAQS). CAIR reduces regional emissions of SO_2 and NO_x (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals issued a decision that would vacate the CAIR and remand the rule to the Federal EPA. In September 2008, the Federal EPA and other parties petitioned for rehearing. Management is unable to predict the outcome of the rehearing petitions or how the Federal EPA will respond to the remand which could be stayed or appealed to the U.S. Supreme Court.

In anticipation of compliance with CAIR in 2009, I&M purchased $9 million of annual CAIR NO_x allowances which are included in Deferred Charges and Other as of September 30, 2008. The market value of annual CAIR NO_x allowances decreased following this court decision. However, the weighted-average cost of these allowances is below market. If CAIR remains vacated, management intends to seek partial recovery of the cost of purchased allowances. Any unrecovered portion would have an adverse effect on future net income and cash flows. None of the other Registrant Subsidiaries purchased any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to the Registrant Subsidiaries' facilities under the Acid Rain Program and the NO_X state implementation plan (SIP) Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

It is too early to determine the full implication of these decisions on environmental compliance strategy. However, independent obligations under the CAA, including obligations under future state implementation plan submittals, and actions taken pursuant to the settlement of the NSR enforcement action, are consistent with the actions included in a least-cost CAIR compliance plan. Consequently, management does not anticipate making any immediate changes in near-term compliance plans as a result of these court decisions.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting I&M

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, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. The Registrant Subsidiaries currently incur costs to safely dispose of these substances.

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. 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 take voluntary action necessary to prevent and/or mitigate public harm. I&M requested remediation proposals from environmental consulting firms. In May 2008, I&M issued a contract to one of the consulting firms. I&M recorded approximately $4 million of expense through September 30, 2008. As the remediation work is completed, I&M's cost may increase. I&M cannot predict the amount of additional cost, if any. At present, management's estimates do not anticipate material cleanup costs for this site.

Cook Plant Unit 1 Fire and Shutdown – Affecting I&M

Cook Plant Unit 1 (Unit 1) is a 1,030 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations likely caused by blade failure which resulted in a fire on the electric generator. This equipment is in the turbine building and is separate and isolated from the nuclear reactor. The steam turbines that caused the vibration were installed in 2006 and are under warranty from the vendor. The warranty provides for the replacement of the turbines if the damage was caused by a defect in the design or assembly of the turbines. I&M is also working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and turbine vendor to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. Management cannot estimate the ultimate costs of the outage at this time. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Management's preliminary analysis indicates that Unit 1 could resume operations as early as late first quarter/early second quarter of 2009 or as late as the second half of 2009, depending upon whether the damaged components can be repaired or whether they need to be replaced.

I&M maintains property insurance through NEIL with a $1 million deductible. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12 week deductible period, I&M is entitled to weekly payments of $3.5 million during the outage period for a covered loss. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

Coal Transportation Rate Dispute - Affecting PSO

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate), and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate, determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. At the end of 1991, PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate, resulting in an underpayment of approximately $9.5 million, including interest.

This matter was submitted to an arbitration board. In April 2006, the arbitration board filed its decision, denying BNSF's underpayments claim. PSO filed a request for an order confirming the arbitration award and a request for entry of judgment on the award with the U.S. District Court for the Northern District of Oklahoma. On July 14, 2006, the U.S. District Court issued an order confirming the arbitration award. On July 24, 2006, BNSF filed a Motion to Reconsider the July 14, 2006 Arbitration Confirmation Order and Final Judgment and its Motion to Vacate and Correct the Arbitration Award with the U.S. District Court. In February 2007, the U.S. District Court granted BNSF's Motion to Reconsider. PSO filed a substantive response to BNSF's motion and BNSF filed a reply. Management continues to defend its position that PSO paid BNSF all amounts owed.

Rail Transportation Litigation – Affecting PSO

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 in United States District Court, Western District of Oklahoma against AEP alleging breach of contract and breach of fiduciary duties related to negotiations for rail transportation services for the plant. The plaintiffs allege that AEP took the duty of the project manager, PSO, and operated the plant for the project manager and is therefore responsible for the alleged breaches. Management intends to vigorously defend against these allegations.

FERC Long-term Contracts – Affecting AEP East companies and AEP West companies

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 AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. Management is unable to predict the outcome of these proceedings or their impact on future net income and cash flows. The Registrant Subsidiaries asserted claims against certain companies that sold power to them, which was resold to the Nevada utilities, seeking to recover a portion of any amounts the Registrant Subsidiaries may owe to the Nevada utilities.

5. ACQUISITION

2008

None

2007

Darby Electric Generating Station – Affecting CSPCo

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.

6. BENEFIT PLANS

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three and nine months ended September 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 25	$ 24	$ 10	$ 11
Interest Cost	62	59	28	26
Expected Return on Plan Assets	(84)	(85)	(27)	(26)
Amortization of Transition Obligation	-	-	7	6
Amortization of Net Actuarial Loss	10	15	3	3
Net Periodic Benefit Cost	$ 13	$ 13	$ 21	$ 20

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 75	$ 72	$ 31	$ 32
Interest Cost	187	176	84	78
Expected Return on Plan Assets	(252)	(254)	(83)	(78)
Amortization of Transition Obligation	-	-	21	20
Amortization of Net Actuarial Loss	29	44	8	9
Net Periodic Benefit Cost	$ 39	$ 38	$ 61	$ 61

The following tables provide the Registrant Subsidiaries' net periodic benefit cost (credit) for the plans for the three and nine months ended September 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
Company	2008	2007	2008	2007
	(in thousands)			
APCo	$ 834	$ 841	$ 3,797	$ 3,560
CSPCo	(351)	(258)	1,545	1,491
I&M	1,821	1,900	2,496	2,530
OPCo	318	362	2,908	2,802
PSO	509	425	1,420	1,431
SWEPCo	935	747	1,411	1,420

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
Company	2008	2007	2008	2007
	(in thousands)			
APCo	$ 2,503	$ 2,525	$ 11,196	$ 10,680
CSPCo	(1,049)	(773)	4,542	4,473
I&M	5,462	5,700	7,342	7,591
OPCo	957	1,088	8,541	8,405
PSO	1,525	1,273	4,194	4,292
SWEPCo	2,806	2,240	4,163	4,258

AEP has significant investments in several trust funds to provide for future pension and OPEB payments. All of the trust funds' investments are well-diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts has declined due to the decreases in the equity and fixed income markets. Although the asset values are currently lower, this decline has not affected the funds' ability to make their required payments.

7. BUSINESS SEGMENTS

The Registrant Subsidiaries have one reportable segment. The one reportable segment is an electricity generation, transmission and distribution business. All of the Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed as one segment because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8. INCOME TAXES

The Registrant Subsidiaries adopted FIN 48 as of January 1, 2007. As a result, the Registrant Subsidiaries recognized an increase in the liabilities for unrecognized tax benefits, as well as related interest expense and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings by each Registrant Subsidiary.

The Registrant Subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its 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.

The Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2000. However, AEP has filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. The Registrant Subsidiaries have completed the exam for the years 2001 through 2003 and have issues that are being pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine their tax returns and the Registrant Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management does not believe that the ultimate resolution of these audits will materially impact net income. With few exceptions, the Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Federal Tax Legislation – Affecting APCo, CSPCo and OPCo

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of a new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. AEP filed applications for the West Virginia and Ohio IGCC projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was allocated credits during the first round of credit awards. After one of the original credit recipients surrendered their credits in the Fall of 2007, the IRS announced a supplemental credit round for the Spring of 2008. AEP filed a new application in 2008 for the West Virginia IGCC project and in July 2008 the IRS allocated the project $134 million in credits. In September 2008, AEP entered into a memorandum of understanding with the IRS concerning the requirements of claiming the credits.

Federal Tax Legislation – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

In October 2008, the Emergency Economic Stabilization Act of 2008 (the Act) was signed into law. The Act extended several expiring tax provisions and added new energy incentive provisions. The legislation impacted the availability of research credits, accelerated depreciation of smart meters, production tax credits and energy efficient commercial building deductions. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income, cash flows or financial condition.

State Tax Legislation – Affecting APCo, CSPCo, I&M and OPCo

In March 2008, the Governor of West Virginia signed legislation 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. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income, cash flows or financial condition.

9. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2008 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
APCo	Pollution Control Bonds	$ 40,000	4.85	2019
APCo	Pollution Control Bonds	30,000	4.85	2019
APCo	Pollution Control Bonds	75,000	Variable	2036
APCo	Pollution Control Bonds	50,275	Variable	2036
APCo	Senior Unsecured Notes	500,000	7.00	2038
CSPCo	Senior Unsecured Notes	350,000	6.05	2018
I&M	Pollution Control Bonds	25,000	Variable	2019
I&M	Pollution Control Bonds	52,000	Variable	2021
I&M	Pollution Control Bonds	40,000	5.25	2025
OPCo	Pollution Control Bonds	50,000	Variable	2014
OPCo	Pollution Control Bonds	50,000	Variable	2014
OPCo	Pollution Control Bonds	65,000	Variable	2036
OPCo	Senior Unsecured Notes	250,000	5.75	2013
SWEPCo	Pollution Control Bonds	41,135	4.50	2011
SWEPCo	Senior Unsecured Notes	400,000	6.45	2019

Company	Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Pollution Control Bonds	$ 40,000	Variable	2019
APCo	Pollution Control Bonds	30,000	Variable	2019
APCo	Pollution Control Bonds	17,500	Variable	2021
APCo	Pollution Control Bonds	50,275	Variable	2036
APCo	Pollution Control Bonds	75,000	Variable	2037
APCo	Senior Unsecured Notes	200,000	3.60	2008
APCo	Other	11	13.718	2026
CSPCo	Pollution Control Bonds	48,550	Variable	2038
CSPCo	Pollution Control Bonds	43,695	Variable	2038
CSPCo	Senior Unsecured Notes	52,000	6.51	2008
CSPCo	Senior Unsecured Notes	60,000	6.55	2008
I&M	Pollution Control Bonds	45,000	Variable	2009
I&M	Pollution Control Bonds	25,000	Variable	2019
I&M	Pollution Control Bonds	52,000	Variable	2021
I&M	Pollution Control Bonds	50,000	Variable	2025
I&M	Pollution Control Bonds	40,000	Variable	2025
I&M	Pollution Control Bonds	50,000	Variable	2025
OPCo	Pollution Control Bonds	50,000	Variable	2014
OPCo	Pollution Control Bonds	50,000	Variable	2016
OPCo	Pollution Control Bonds	50,000	Variable	2022
OPCo	Pollution Control Bonds	35,000	Variable	2022
OPCo	Pollution Control Bonds	65,000	Variable	2036
OPCo	Notes Payable	1,463	6.81	2008
OPCo	Notes Payable	12,000	6.27	2009
PSO	Pollution Control Bonds	33,700	Variable	2014
SWEPCo	Pollution Control Bonds	41,135	Variable	2011
SWEPCo	Notes Payable	1,500	Variable	2008
SWEPCo	Notes Payable	3,304	4.47	2011

In October 2008, SWEPCo retired $113 million of 5.25% Notes Payable due in 2043.

As of September 30, 2008, OPCo and SWEPCo had $218 million and $54 million, respectively, of tax-exempt long-term debt sold at auction rates that reset every 35 days. These auction rates ranged from 11.117% to 13% for OPCo. SWEPCo's rate was 4.353%. OPCo's $218 million of debt relates to a lease structure with JMG that OPCo is unable to refinance at this time. In order to refinance this debt, OPCo needs the lessor's consent. This debt is insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation and Financial Guaranty Insurance Co. Due to the exposure that these bond insurers had in connection with recent developments in the subprime credit market, the credit ratings of these insurers were downgraded or placed on negative outlook. These market factors contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions, including many of the auctions of tax-exempt long-term debt. Consequently, the Registrant Subsidiaries chose to exit the auction-rate debt market. The instruments under which the bonds are issued allow for conversion to other short-term variable-rate structures, term-put structures and fixed-rate structures. Through September 30, 2008, the Registrant Subsidiaries reduced their outstanding auction rate securities. Management plans to continue this conversion and refunding process for the remaining $272 million to other permitted modes, including term-put structures, variable-rate and fixed-rate structures, as opportunities arise.

As of September 30, 2008, $367 million of the prior auction rate debt was issued in a weekly variable rate mode supported by letters of credit at variable rates ranging from 6.5% to 8.25% and $333 million was issued at fixed rates ranging from 4.5% to 5.25%. As of September 30, 2008, trustees held, on behalf of the Registrant Subsidiaries, approximately $330 million of their reacquired auction rate tax-exempt long-term debt which management plans to reissue to the public as market conditions permit. The following table shows the current status of debt which was issued as auction rate debt at December 31, 2007:

Company	Retired in 2008	Remarketed at Fixed Rates During the First Nine Months of 2008	Fixed Rate at September 30, 2008	Remarketed at Variable Rates During the First Nine Months of 2008	Variable Rate at September 30, 2008	Remains at Auction Rate at September 30, 2008	Held by Trustee at September 30, 2008
	(in thousands)			(in thousands)		(in thousands)	
APCo	$ -	$ 30,000	4.85%	$ 75,000	8.00%	$ -	$ 17,500
APCo	-	40,000	4.85%	50,275	8.05%	-	-
CSPCo	-	56,000	5.10%	-	-	-	92,245
CSPCo	-	44,500	4.85%	-	-	-	-
I&M	45,000	40,000	5.25%	52,000	7.75%	-	100,000
I&M	-	-	-	25,000	8.25%	-	-
OPCo	-	-	-	65,000	6.50%	218,000	85,000
OPCo	-	-	-	50,000	7.83%	-	-
OPCo	-	-	-	50,000	7.50%	-	-
PSO	-	-	-	-	-	-	33,700
SWEPCo	-	81,700	4.95%	-	-	53,500	-
SWEPCo	-	41,135	4.50%	-	-	-	-
Total	$ 45,000	$ 333,335		$ 367,275		$ 271,500	$ 328,445

Lines of Credit

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of September 30, 2008 and December 31, 2007 are included in Advances to/from Affiliates on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the nine months ended September 30, 2008 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of September 30, 2008	Authorized Short-Term Borrowing Limit
	(in thousands)					
APCo	$ 307,226	$ 269,987	$ 188,985	$ 187,192	$ (93,558)	$ 600,000
CSPCo	238,172	150,358	157,569	53,962	21,833	350,000
I&M	345,064	-	195,582	-	(224,071)	500,000
OPCo	415,951	82,486	174,840	64,127	39,758	600,000
PSO	149,278	59,384	72,688	29,811	(125,029)	300,000
SWEPCo	168,495	300,525	87,426	219,159	195,628	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Nine Months Ended September 30, 2008	2007
Maximum Interest Rate	5.37%	5.94%
Minimum Interest Rate	2.91%	5.30%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the nine months ended September 30, 2008 and 2007 are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Nine Months Ended September 30, 2008	2007	Average Interest Rate for Funds Loaned to the Utility Money Pool for the Nine Months Ended September 30, 2008	2007
APCo	3.62%	5.41%	3.25%	5.84%
CSPCo	3.66%	5.48%	2.99%	5.39%
I&M	3.19%	5.38%	-%	5.84%
OPCo	3.24%	5.39%	3.62%	5.43%
PSO	3.04%	5.47%	4.53%	-%
SWEPCo	3.36%	5.54%	3.01%	5.34%

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		September 30, 2008		December 31, 2007	
Company	**Type of Debt**	**Outstanding Amount (in thousands)**	**Interest Rate (a)**	**Outstanding Amount (in thousands)**	**Interest Rate (a)**
OPCo	Commercial Paper – JMG (b)	$ -	-%	$ 701	5.35%
SWEPCo	Line of Credit – Sabine Mining Company (c)	9,520	7.75%	285	5.25%

(a) Weighted average rate.
(b) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility.
(c) Sabine Mining Company is consolidated under FIN 46R.

Credit Facilities

In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, letters of credit may be issued. As of September 30, 2008, $372 million of letters of credit were issued by Registrant Subsidiaries under the 3-year credit agreement to support variable rate demand notes.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and net income and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements and (iii) footnotes of each individual registrant. The combined Management's Discussion and Analysis of Registrant Subsidiaries section of the 2007 Annual Report should also be read in conjunction with this report.

Market Impacts

In recent months, the world and U.S. economies have experienced significant slowdowns. These economic slowdowns have impacted and will continue to impact the Registrant Subsidiaries' residential, commercial and industrial sales. Concurrently, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting the Registrant Subsidiaries' access to capital, liquidity, asset valuations in trust funds, creditworthy status of customers, suppliers and trading partners and cost of capital. AEP's financial staff actively manages these factors with oversight from the risk committee. The uncertainties in the credit markets could have significant implications since the Registrant Subsidiaries rely on continuing access to capital to fund operations and capital expenditures.

The current credit markets are constraining the Registrant Subsidiaries' ability to issue new debt and refinance existing debt. Approximately $120 million and $300 million of AEP Consolidated's $16 billion of long-term debt as of September 30, 2008 will mature in the remainder of 2008 and 2009, respectively. I&M and OPCo have $50 million and $37 million, respectively, maturing in 2008. APCo, OPCo and PSO have $150 million, $82 million and $50 million, respectively, maturing in 2009. Management intends to refinance these maturities. To support its operations, AEP has $3.9 billion in aggregate credit facility commitments. These commitments include 27 different banks with no bank having more than 10% of the total bank commitments. Short-term funding for the Registrant Subsidiaries comes from AEP's commercial paper program credit facilities which supports the Utility Money Pool. In September 2008 and October 2008, AEP borrowed $600 million and $1.4 billion, respectively, under the credit facilities to enhance its cash position during this period of market disruptions. This money can be loaned to the Registrant Subsidiaries through the Utility Money Pool.

Management cannot predict the length of time the current credit situation will continue or its impact on future operations and the Registrant Subsidiaries' ability to issue debt at reasonable interest rates. However, when market conditions improve, management plans to repay the amounts drawn under the credit facilities, re-enter the commercial paper market and issue long-term debt. If there is not an improvement in access to capital, management believes that the Registrant Subsidiaries have adequate liquidity, through the Utility Money Pool, to support their planned business operations and construction programs through 2009.

AEP has significant investments in several trust funds to provide for future payments of pensions and OPEB. I&M has significant investments in several trust funds to provide for future payments of nuclear decommissioning and spent nuclear fuel disposal. All of the trust funds' investments are well-diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts has declined due to the decreases in the equity and fixed income markets. Although the asset values are currently lower, this has not affected the funds' ability to make their required payments. As of September 30, 2008, the decline in pension asset values will not require a contribution to be made in 2008 or 2009.

On behalf of the Registrant Subsidiaries, AEPSC enters into risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. AEP's risk management organization monitors these exposures on a daily basis to limit the Registrant Subsidiaries' economic and financial statement impact on a counterparty basis.

Sources of Funding

The credit facilities that support the Utility Money Pool were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $46 million following its bankruptcy. In March 2008, these credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit (LOC). Certain companies within the AEP System including the Registrant Subsidiaries operate the Utility Money Pool to minimize external short-term funding requirements. The Registrant Subsidiaries also sell accounts receivable to provide liquidity. The Registrant Subsidiaries generally use short-term funding sources (the Utility Money Pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leaseback, leasing arrangements and additional capital contributions from AEP.

In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. The Registrant Subsidiaries may issue LOCs under the credit facilities. Each subsidiary has a borrowing/LOC limit under the credit facilities. As of September 30, 2008, a total of $372 million of LOCs were issued under the 3-year credit agreement to support variable rate demand notes. The following table shows each Registrant Subsidiaries' borrowing/LOC limit under each credit facility and the outstanding amount of LOCs for the $650 million facility.

Company	$650 million Credit Facility Borrowing/LOC Limit	$350 million Credit Facility Borrowing/LOC Limit	LOC Amount Outstanding Against $650 million Agreement at September 30, 2008
		(in millions)	
APCo	$ 300	$ 150	$ 127
CSPCo	230	120	-
I&M	230	120	78
OPCo	400	200	167
PSO	65	35	-
SWEPCo	230	120	-

At September 30, 2008, there were no outstanding amounts under the $350 million facility.

Credit Markets

To the extent financing is unavailable due to the challenging credit markets, the Registrant Subsidiaries will rely upon cash flows from operations and access to the Utility Money Pool to fund their debt maturities, continuing operations and capital expenditures.

In the first quarter of 2008, due to the exposure that bond insurers like Ambac Assurance Corporation and Financial Guaranty Insurance Co. had in connection with developments in the subprime credit market, the credit ratings of those insurers were downgraded or placed on negative outlook. These market factors contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions for tax-exempt long-term debt sold at auction rates. Consequently, management chose to exit the auction-rate debt market. As of September 30, 2008, OPCo had $218 million (rates range from 11.117% to 13%) and SWEPCo had $54 million (rate of 4.353%) outstanding of tax-exempt long-term debt sold at auction rates that reset every 35 days. Approximately $218 million of this debt relates to a lease structure with JMG that OPCo is unable to refinance at this time. In order to refinance this debt, OPCo needs the lessor's consent. This debt is insured by previously AAA-rated bond insurers. The instruments under which the bonds are issued allow for their conversion to other short-term variable-rate structures, term-put structures and fixed-rate structures. Management plans to continue the conversion and refunding process to other permitted modes, including term-put structures, variable-rate and fixed-rate structures, as opportunities arise. Through September 30, 2008, the Registrant Subsidiaries reduced their outstanding auction rate securities.

As of September 30, 2008, trustees held, on behalf of the Registrant Subsidiaries, approximately $330 million of their reacquired auction rate tax-exempt long-term debt which management plans to reissue to the public as the market permits. The following table shows the current status of debt that was issued as auction rate at December 31, 2007 by Registrant Subsidiary.

Company	Retired in 2008	Remarketed at Fixed or Variable Rates During 2008	Remains in Auction Rate at September 30, 2008	Held by Trustee at September 30, 2008
	(in millions)			
APCo	$ -	$ 195	$ -	$ 18
CSPCo	-	101	-	92
I&M	45	117	-	100
OPCo	-	165	218	85
PSO	-	-	-	34
SWEPCo	-	123	54	-

APCo, I&M and OPCo issued $125 million, $77 million and $165 million, respectively, of weekly variable rate debt. As of September 30, 2008, the variable rates ranged from 6.5% to 8.25%. APCo issued fixed rate debt of $70 million at 4.85% until 2019. CSPCo issued fixed rate debt of $45 million at 4.85% until 2012 and $56 million at 5.1% until 2013. I&M issued $40 million of fixed rate debt at 5.25% due 2025. SWEPCo remarketed $82 million of fixed rate debt at 4.95% due 2018 and issued $41 million of fixed rate debt at 4.5% through 2011.

Sales of Receivable Agreement

In October 2008, AEP Credit renewed its $600 million sale of receivables agreement through October 2009. AEP Credit purchases accounts receivable from the Registrant Subsidiaries.

Capital Expenditures

Due to recent credit market instability, management is currently reviewing projections for capital expenditures for 2009 through 2010. Management plans to identify reductions of approximately $750 million for 2009 across the AEP System. Management is evaluating possible additional capital reductions for 2010. Management is also reviewing projections for operation and maintenance expense. Management's intent is to keep operation and maintenance expense flat in 2009 as compared to 2008.

Significant Factors

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amends the restructuring law effective July 31, 2008 and requires electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities may file an ESP with a fuel cost recovery mechanism. Electric utilities also have an option to file a Market Rate Offer (MRO) for generation pricing. An MRO, from the date of its commencement, could transition CSPCo and OPCo to full market rates no sooner than six years and no later than ten years after the PUCO approves an MRO. The PUCO has the authority to approve or modify the utilities' ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than the MRO. Both alternatives involve a "substantially excessive earnings" test based on what public companies, including other utilities with similar risk profiles, earn on equity. Management has preliminarily concluded, pending the outcome of the ESP proceeding, that CSPCo's and OPCo's generation/supply operations are not subject to cost-based rate regulation accounting. However, if a fuel cost recovery mechanism is implemented within the ESP, CSPCo's and OPCo's fuel and purchased power operations would be subject to cost-based rate regulation accounting. Management is unable to predict the financial statement impact of the restructuring legislation until the PUCO acts on specific proposals made by CSPCo and OPCo in their ESPs.

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file an optional MRO. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism (which excludes off-system sales) that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The increases in customer bills related to the fuel-purchased power cost recovery mechanism would be phased-in over the three year period from 2009 through 2011. If the ESP is approved as filed, effective with January 2009 billings, CSPCo and OPCo will defer any fuel cost under-recoveries and related carrying costs for future recovery. The under-recoveries and related carrying costs that exist at the end of 2011 will be recovered over seven years from 2012 through 2018. In addition to the fuel cost recovery mechanisms, the requested increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for distribution reliability costs and for unexpected non-fuel generation costs. The filings also include programs for smart metering initiatives and economic development and mandated energy efficiency and peak demand reduction programs. In September 2008, the PUCO issued a finding and order tentatively adopting rules governing MRO and ESP applications. CSPCo and OPCo filed their ESP applications based on proposed rules and requested waivers for portions of the proposed rules. The PUCO denied the waiver requests in September 2008 and ordered CSPCo and OPCo to submit information consistent with the tentative rules. In October 2008, CSPCo and OPCo submitted additional information related to proforma financial statements and information concerning CSPCo and OPCo's fuel procurement process. In October 2008, CSPCo and OPCo filed an application for rehearing with the PUCO to challenge certain aspects of the proposed rules.

Within the ESPs, CSPCo and OPCo would also recover existing regulatory assets of $46 million and $38 million, respectively, for customer choice implementation and line extension carrying costs. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $30 million and $21 million, respectively. Such costs would be recovered over an 8-year period beginning January 2011. Hearings are scheduled for November 2008 and an order is expected in the fourth quarter of 2008. Failure of the PUCO to ultimately approve the recovery of the regulatory assets would have an adverse effect on future net income and cash flows.

New Generation

In 2008, AEP completed or is in various stages of construction of the following generation facilities:

Operating Company	Project Name		Location	Total Projected Cost (a) (in millions)	CWIP (b) (in millions)	Fuel Type	Plant Type	Nominal MW Capacity	Commercial Operation Date (Projected)
PSO	Southwestern	(c)	Oklahoma	$ 56	$ -	Gas	Simple-cycle	150	2008
PSO	Riverside	(d)	Oklahoma	58	-	Gas	Simple-cycle	150	2008
AEGCo	Dresden	(e)	Ohio	309(e)	149	Gas	Combined-cycle	580	2010(h)
SWEPCo	Stall		Louisiana	378	158	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(f)	Arkansas	1,522(f)	448	Coal	Ultra-supercritical	600(f)	2012
APCo	Mountaineer	(g)	West Virginia	(g)		Coal	IGCC	629	(g)
CSPCo/OPCo	Great Bend	(g)	Ohio	(g)		Coal	IGCC	629	(g)

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) Southwestern Units were placed in service on February 29, 2008.
(d) The final Riverside Unit was placed in service on June 15, 2008.
(e) In September 2007, AEGCo purchased the partially completed Dresden plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the "Total Projected Cost" section above.
(f) SWEPCo plans to own approximately 73%, or 440 MW, totaling $1.1 billion in capital investment. The increase in the cost estimate disclosed in the 2007 Annual Report relates to cost escalations due to the delay in receipt of permits and approvals. See "Turk Plant" section below.
(g) Construction of IGCC plants are pending necessary permits and regulatory approval. See "IGCC Plants" section below.
(h) Projected completion date of the Dresden Plant is currently under review. To the extent that the completion date is delayed, the total projected cost of the Dresden Plant could change.

Turk Plant

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant.

In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the $1.5 billion projected construction cost, excluding AFUDC, (b) capping CO_2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. An intervenor filed a motion for rehearing seeking reversal of the PUCT's decision. SWEPCo filed a motion for rehearing stating that the two cost cap restrictions are unlawful. In September 2008, the motions for rehearing were denied. In October 2008, SWEPCo appealed the PUCT's order regarding the two cost cap restrictions. If the cost cap restrictions are upheld and construction or emissions costs exceed the restrictions, it could have a material adverse impact on future net income and cash flows. In October 2008, an intervenor filed an appeal contending that the PUCT's grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

SWEPCo is also working with the Arkansas Department of Environmental Quality for the approval of an air permit and the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. Once SWEPCo receives the air permit, they will commence construction. A request to stop pre-construction activities at the site was filed in federal court by the same Arkansas landowners who appealed the APSC decision to the Arkansas State Court of Appeals. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In January 2008 and July 2008, SWEPCo filed applications for authority with the APSC to construct transmission lines necessary for service from the Turk Plant. Several landowners filed for intervention status and one landowner also contended he should be permitted to re-litigate Turk Plant issues, including the need for the generation. The APSC granted their intervention but denied the request to re-litigate the Turk Plant issues. The landowner filed an appeal to the Arkansas State Court of Appeals in June 2008.

The Arkansas Governor's Commission on Global Warming is scheduled to issue its final report to the Governor by November 1, 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. If legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's proposal to build the Turk Plant.

If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of September 30, 2008, SWEPCo has capitalized approximately $448 million of expenditures and has significant contractual construction commitments for an additional $771 million. As of September 30, 2008, if the plant had been cancelled, cancellation fees of $61 million would have been required in order to terminate these construction commitments. If the Turk Plant does not receive all necessary approvals on reasonable terms and SWEPCo cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

IGCC Plants

The construction of the West Virginia and Ohio IGCC plants are pending necessary permits and regulatory approvals. In May 2008, the Virginia SCC denied APCo's request to reconsider the Virginia SCC's previous denial of APCo's request to recover initial costs associated with a proposed IGCC plant in West Virginia. In July 2008, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed regarding its earlier approval of the IGCC plant. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expenses being incurred and certification of the IGCC plant prior to July 2010. Through September 30, 2008, APCo deferred for future recovery preconstruction IGCC costs of $19 million. If the West Virginia IGCC plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

In Ohio, CSPCo and OPCo continue to pursue the ultimate construction of the IGCC plant. In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all Phase 1 cost recoveries be refunded to Ohio ratepayers with interest. CSPCo and OPCo filed a response with the PUCO that argued the Ohio Consumers' Counsel's motion was without legal merit and contrary to past precedent. If CSPCo and OPCo were required to refund some or all of the $24 million collected for IGCC pre-construction costs and those costs were not recoverable in another jurisdiction in connection with the construction of an IGCC plant, it would have an adverse effect on future net income and cash flows.

Environmental Matters

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

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

In addition, the Registrant Subsidiaries are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of spent nuclear fuel and future decommissioning of I&M's nuclear units. Management is also engaged in the development of possible future requirements to reduce CO_2 and other greenhouse gas (GHG) emissions to address concerns about global climate change. All of these matters are discussed in the "Environmental Matters" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2007 Annual Report.

Clean Air Act Requirements

As discussed in the 2007 Annual Report under "Clean Air Act Requirements," various states and environmental organizations challenged the Clean Air Mercury Rule (CAMR) in the D. C. Circuit Court of Appeals. The court ruled that the Federal EPA's action delisting fossil fuel-fired power plants did not conform to the procedures specified in the CAA. The court vacated and remanded the model federal rules for both new and existing coal-fired power plants to the Federal EPA. The Federal EPA filed a petition for review by the U.S. Supreme Court. Management is unable to predict the outcome of this appeal or how the Federal EPA will respond to the remand. In addition, in 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR), that requires further reductions in SO_2 and NO_x emissions and assists states developing new state implementation plans to meet 1997 national ambient air quality standards (NAAQS). CAIR reduces regional emissions of SO_2 and NO_x (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO_2 by 50% by 2010, and by 65% by 2015. NO_x emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70% from current levels by 2015. Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals vacated the CAIR and remanded the rule to the Federal EPA. The Federal EPA and other parties petitioned for rehearing. Management is unable to predict the outcome of the rehearing petitions or how the Federal EPA will respond to the remand which could be stayed or appealed to the U.S. Supreme Court. The Federal EPA also issued revised NAAQS for both ozone and $PM_{2.5}$ that are more stringent than the 1997 standards used to establish CAIR, which could increase the levels of SO_2 and NO_x reductions required from the AEP System's facilities.

In anticipation of compliance with CAIR in 2009, I&M purchased $9 million of annual CAIR NO_x allowances. The market value of annual CAIR NO_x allowances decreased following this court decision. However, the weighted-average cost of these allowances is below market. If CAIR remains vacated, management intends to seek partial recovery of the cost of purchased allowances. Any unrecovered portion would have an adverse effect on future net income and cash flows. None of the other Registrant Subsidiaries purchased any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to the Registrant Subsidiaries' facilities under the Acid Rain Program and the NO_X state implementation plan (SIP) Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

It is too early to determine the full implication of these decisions on the AEP System's environmental compliance strategy. However, independent obligations under the CAA, including obligations under future state implementation plan submittals, and actions taken pursuant to the settlement of the NSR enforcement action, are consistent with the actions included in the AEP System's least-cost CAIR compliance plan. Consequently, management does not anticipate making any immediate changes in the near-term compliance plans as a result of these court decisions.

Global Climate Change

In July 2008, the Federal EPA issued an advance notice of proposed rulemaking (ANPR) that requests comments on a wide variety of issues the agency is considering in formulating its response to the U.S. Supreme Court's decision in *Massachusetts v. EPA*. In that case, the court determined that CO_2 is an "air pollutant" and that the Federal EPA has authority to regulate mobile sources of CO_2 emissions under the CAA if appropriate findings are made. The Federal EPA has identified a number of issues that could affect stationary sources, such as electric generating plants, if the necessary findings are made for mobile sources, including the potential regulation of CO_2 emissions for both new and existing stationary sources under the NSR programs of the CAA. Management plans to submit comments and participate in any subsequent regulatory development processes, but are unable to predict the outcome of the Federal EPA's administrative process or its impact on the AEP System's business. Also, additional legislative measures to address CO_2 and other GHGs have been introduced in Congress, and such legislative actions could impact future decisions by the Federal EPA on CO_2 regulation.

In addition, the Federal EPA issued a proposed rule for the underground injection and storage of CO_2 captured from industrial processes, including electric generating facilities, under the Safe Drinking Water Act's Underground Injection Control (UIC) program. The proposed rules provide a comprehensive set of well siting, design, construction, operation, closure and post-closure care requirements. Management plans to submit comments and participate in any subsequent regulatory development process, but are unable to predict the outcome of the Federal EPA's administrative process or its impact on the AEP System's business. Permitting for a demonstration project at the Mountaineer Plant will proceed under the existing UIC rules.

Clean Water Act Regulation

In 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen or entrained in the cooling water. The standards vary based on the water bodies from which the plants draw their cooling water. Management expected additional capital and operating expenses, which the Federal EPA estimated could be $193 million for the AEP System's plants. The Registrant Subsidiaries undertook site-specific studies and have been evaluating site-specific compliance or mitigation measures that could significantly change these cost estimates. The following table shows the investment amount per Registrant Subsidiary.

Company	Estimated Compliance Investments (in millions)
APCo	$ 21
CSPCo	19
I&M	118
OPCo	31

In January 2007, the Second Circuit Court of Appeals issued a decision remanding significant portions of the rule to the Federal EPA. In July 2007, the Federal EPA suspended the 2004 rule, except for the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the 2004 rule is the applicable standard for permitting agencies pending finalization of revised rules by the Federal EPA. Management cannot predict further action of the Federal EPA or what effect it may have on similar requirements adopted by the states. The Registrant Subsidiaries sought further review and filed for relief from the schedules included in their permits.

In April 2008, the U.S. Supreme Court agreed to review decisions from the Second Circuit Court of Appeals that limit the Federal EPA's ability to weigh the retrofitting costs against environmental benefits. Management is unable to predict the outcome of this appeal.

Adoption of New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity includes its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data. In February 2008, the FASB issued FSP SFAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). In October 2008, the FASB issued FSP SFAS 157-3 "Determining the Fair Value of Financial Asset When the Market for That Asset is Not Active" which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. The Registrant Subsidiaries partially adopted SFAS 157 effective January 1, 2008. FSP SFAS 157-3 is effective upon issuance. The Registrant Subsidiaries will fully adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP SFAS 157-2. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, APCo, CSPCo and OPCo reduced beginning retained earnings by $440 thousand ($286 thousand, net of tax), $486 thousand ($316 thousand, net of tax) and $434 thousand ($282 thousand, net of tax), respectively, for the transition adjustment. SWEPCo's transition adjustment was a favorable $16 thousand ($10 thousand, net of tax) adjustment to beginning retained earnings. The impact of considering AEP's credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption. See "SFAS 157 "Fair Value Measurements" (SFAS 157)" section of Note 2.

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. The statement is applied prospectively upon adoption. The Registrant Subsidiaries adopted SFAS 159 effective January 1, 2008. At adoption, the Registrant Subsidiaries did not elect the fair value option for any assets or liabilities.

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pension" or Accounting Principles Board Opinion No. 12 "Omnibus Opinion – 1967" if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. The Registrant Subsidiaries adopted EITF 06-10 effective January 1, 2008. The impact of this standard was an unfavorable cumulative effect adjustment, net of tax, to beginning retained earnings as follows:

Company	Retained Earnings Reduction	Tax Amount
	(in thousands)	
APCo	$ 2,181	$ 1,175
CSPCo	1,095	589
I&M	1,398	753
OPCo	1,864	1,004
PSO	1,107	596
SWEPCo	1,156	622

In June 2007, the FASB ratified the EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11), consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. The Registrant Subsidiaries adopted EITF 06-11 effective January 1, 2008. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after December 15, 2007. The adoption of this standard had an immaterial impact on the Registrant Subsidiaries' financial statements.

In April 2007, the FASB issued FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1). It amends FASB Interpretation No. 39 "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period. The Registrant Subsidiaries adopted FIN 39-1 effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. See "FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)" section of Note 2. Consequently, the Registrant Subsidiaries reduced total assets and liabilities on their December 31, 2007 balance sheet as follows:

Company	(in thousands)
APCo	$ 7,646
CSPCo	4,423
I&M	4,251
OPCo	5,234
PSO	187
SWEPCo	229

CONTROLS AND PROCEDURES

During the third quarter of 2008, management, including the principal executive officer and principal financial officer of each of AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo (collectively, the Registrants), evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of September 30, 2008 these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of 2008 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see Note 4, *Commitments, Guarantees and Contingencies,* incorporated herein by reference.

Item 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2007 includes a detailed discussion of our risk factors. The information presented below amends and restates in their entirety certain of those risk factors that have been updated and should be read in conjunction with the risk factors and information disclosed in our 2007 Annual Report on Form 10-K.

General Risks of Our Regulated Operations

Our request for rate recovery in Oklahoma may not be approved. *(Applies to AEP and PSO)*

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million on an annual basis (including an estimated $16 million that is being recovered through a rider). The proposed revenue requirement reflects a return on equity of 11.25%. In October 2008, intervenors filed testimony recommending annual base rate increases ranging from $29 million to $86 million. The differences are principally due to lower recommended returns on equity. If the OCC denies all or part of the requested rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Our request for rate recovery in Ohio may not be approved. *(Applies to AEP, OPCo and CSPCo)*

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism that primarily includes fuel costs, purchased power costs including renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. Management expects a PUCO decision on the ESP filings in the fourth quarter of 2008. If an order is not received prior to January 1, 2009, CSPCo and OPCo have requested retroactive application of the new rates back to January 1, 2009 upon approval. If the PUCO denies all or part of the requested rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Our request for rate recovery in Virginia may not be approved. *(Applies to AEP and APCo)*

In May 2008, APCo filed an application with the Virginia SCC to increase its base rates by $208 million on an annual basis. The proposed revenue requirement reflects a return on equity of 11.75%. In October 2008, the Virginia SCC staff filed testimony recommending the proposed increase be reduced to $157 million. The decrease is principally due to the use of a recommended return on equity of 10.1%. In October 2008, hearings were held in which APCo filed a $168 million settlement agreement which was accepted by all parties except one industrial customer. If the Virginia SCC denies all or part of the requested rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Our request for rate recovery in Indiana may not be approved. *(Applies to AEP and I&M)*

In a January 2008 filing with the IURC, updated in the second quarter of 2008, I&M requested an increase in its Indiana base rates of $80 million including a return on equity of 11.5%. In September 2008, the Indiana Office of Utility Consumer Counselor (OUCC) and the Industrial Customer Coalition filed testimony recommending a $14 million and $37 million decrease in revenue, respectively. In October 2008, I&M filed testimony rebutting the recommendations of the OUCC. Hearings are scheduled for December 2008. A decision is expected from the IURC by June 2009. If the IURC denies all or part of the requested rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Risks Related to Owning and Operating Generation Assets and Selling Power

Our financial performance may be impaired if Cook Plant Unit 1 is not returned to service in a reasonable period of time or in a cost-efficient manner. *(Applies to AEP and I&M)*

Cook Plant Unit 1 is a 1,055 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to a fire on the electric generator which resulted from steam turbine vibrations. I&M is working with its insurance company and turbine vendor to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. At this time, management is unable to determine the ultimate costs of the incident or when the unit will return to service. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance, other reimbursements or the regulatory process. If any of these costs are not covered by warranty, insurance or recovered through the regulatory process, or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

The different regional power markets in which we compete or will compete in the future have changing transmission regulatory structures, which could affect our performance in these regions. *(Applies to AEP, APCo, CSPCo, I&M and OPCo)*

FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. In December 2007, AEP filed its most recent triennial update. In 2008, the PUCO filed comments suggesting that FERC should further investigate whether certain utilities, including AEP, continue to pass FERC's indicative screens for the lack of market power in PJM. Certain industrial retail customers also urged FERC to further investigate this matter. In September 2008, the FERC issued an order accepting AEP's market-based rates with minor changes and rejected the PUCO's and the industrial retail customers' suggestions for further investigation. If FERC limits AEP's ability to sell power at market based rates in PJM, it could have an adverse effect on future off-system sales margins, net income and cash flows.

Our costs of compliance with environmental laws are significant and the cost of compliance with future environmental laws could harm our cash flow and profitability or cause some of our electric generating units to be uneconomical to maintain or operate. *(Applies to each registrant)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past, and we expect that they will increase in the future. Further, environmental advocacy groups, other organizations and some agencies in the United States are focusing considerable attention on CO_2 emissions from power generation facilities and their potential role in climate change. Although several bills have been introduced in Congress that would compel CO_2 emission reductions, none have advanced through the legislature. In April 2007 the U.S. Supreme Court determined that CO_2 is an "air pollutant" and that the Federal EPA has authority to regulate CO_2 emissions under the CAA. In July 2008 the Federal EPA issued an advance notice of proposed rulemaking (ANPR) that requests comments on a wide variety of issues in response to the U.S. Supreme Court's decision. The ANPR could lead to regulations limiting the emissions of CO_2 from our generating plants. Costs of compliance with environmental regulations could adversely affect our net income and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including timing of implementation, required levels of reductions, allocation requirements of the new rules and our selected compliance alternatives. As a result, we cannot estimate our compliance costs with certainty. The actual costs to comply could differ significantly from our estimates. All of the costs are incremental to our current investment base and operating cost structure. In addition, any legal obligation that would require us to substantially reduce our emissions beyond present levels could require extensive mitigation efforts and, in the case of CO_2 legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices (in Ohio and Texas), without such recovery those costs could adversely affect future net income and cash flows, and possibly financial condition.

Risks Related to Market, Economic or Financial Volatility

If we are unable to access capital markets on reasonable terms, it could have an adverse impact on our net income, cash flows and financial condition. *(Applies to each registrant)*

We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. The recent volatility and reduced liquidity in the financial markets could affect our ability to raise capital and fund our capital needs, including construction costs and refinancing maturing indebtedness. In addition, if capital is available only on less than reasonable terms, interest costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could have an adverse impact on net income, cash flows and financial condition.

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses. *(Applies to each registrant)*

Since the bankruptcy of Enron, the credit ratings agencies have periodically reviewed our capital structure and the quality and stability of our earnings. Any negative ratings actions could constrain the capital available to our industry and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed and future net income could be adversely affected.

If Moody's or S&P were to downgrade the long-term rating of any of the securities of the registrants**,** particularly below investment grade, the borrowing costs of that registrant would increase, which would diminish its financial results. In addition, the registrant's potential pool of investors and funding sources could decrease. In the first quarter of 2008, Fitch downgraded the senior unsecured debt rating of PSO and SWEPCo to BBB+ with stable outlook. Moody's placed the senior unsecured debt rating of APCo, OPCo, SWEPCo and TCC on negative outlook in January 2008. Moody's assigns the following ratings to the senior unsecured debt of these companies: APCo Baa2, OPCo A3, SWEPCo Baa1 and TCC Baa2.

Our power trading business relies on the investment grade ratings of our individual public utility subsidiaries' senior unsecured long-term debt. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If those ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

In Ohio, we have limited ability to pass on our fuel costs to our customers. *(Applies to AEP, CSPCo and OPCo)*

See risk factor above "Our request for rate recovery in Ohio may not be approved."

Risks Relating to State Restructuring

In Ohio, our future rates are uncertain. *(Applies to AEP, OPCo and CSPCo)*

See risk factor above "Our request for rate recovery in Ohio may not be approved."

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended September 30, 2008 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
07/01/08 – 07/31/08	-	$ -	-	$ -
08/01/08 – 08/31/08	-	-	-	-
09/01/08 – 09/30/08	-	-	-	-

Item 4. Submission of Matters to a Vote of Security Holders

NONE

Item 5. Other Information

NONE

Item 6. Exhibits

AEP

10(a) – Second Amended and Restated $1.5 Billion Credit Agreement, dated as of March 31, 2008, among AEP, the banks, financial institutions and other institutional lenders listed on the signatures pages thereof, and JPMorgan Chase Bank, N.A., as Administrative Agent.
10(b) – Second Amended and Restated $1.5 Billion Credit Agreement, dated as of March 31, 2008, among AEP, the banks, financial institutions and other institutional lenders listed on the signatures pages thereof, and Barclays Bank plc, as Administrative Agent.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

10(c) – $650 Million Credit Agreement, dated as of April 4, 2008. among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.
10(d) – Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.
10(e) – $350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.
10(f) – Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

31(a) – Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b) – Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.
32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: October 31, 2008